# Grand Banks Gas for Power Generation in Newfoundland

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Presentation to:

SSPE – Student Society of Petroleum Engineers

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Society of Petroleum Engineers

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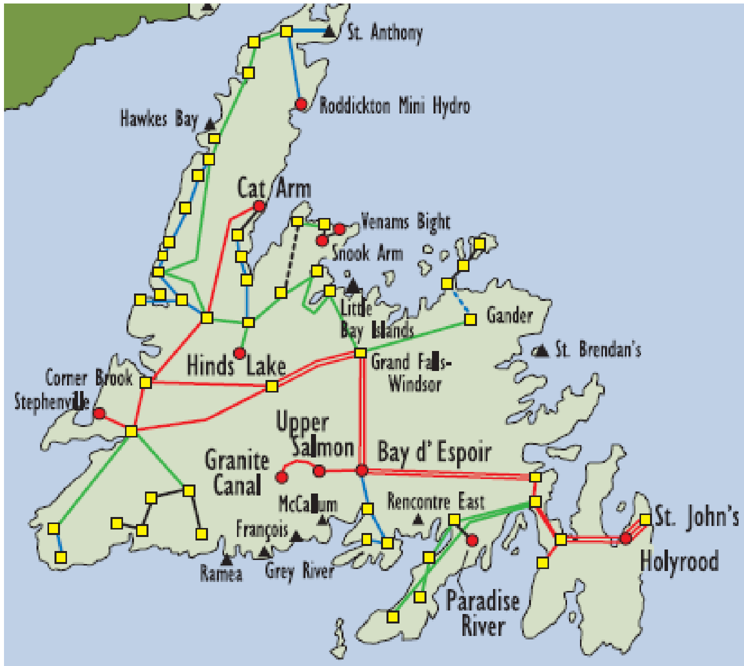
# Electrical Energy Picture

**Newfoundland has an insular grid w/ approx 2000 MW installed capacity. Approx 500 MW thermal at Holyrood, hydraulic elsewhere and small thermal plants in isolated areas.**

**Upper Churchill capacity near 5400MW and the proposed Lower Churchill capacity is around 2000MW.**




**LEGEND**

Generating Station | Terminal Station | Diesel Plant

Transmission Lines

| | | |
|---|---|---|
| 735-kV | 138-kV | Low Voltage |
| 230-kV | 69-kV | Customer-Owned |

**2005 GROSS ISLAND INTERCONNECTED ENERGY SUPPLY**

Gigawatt hours (GWh)

| | |
|---|---|
| Hydraulic Generation | |
| Bay D' Espoir | 2,847 |
| Cat Arm | 684 |
| Upper Salmon | 590 |
| Hinds Lake | 376 |
| Granite Canal | 243 |
| Paradise River | 39 |
| Mini Hydro | 7 |
| | 4,786 |
| Percentage of Total Energy Supply | 72% |

| | |
|---|---|
| Power Purchases | 423 |
| Percentage of Total Energy Supply | 6% |
| Thermal Generation | |
| Holyrood | 1,414 |
| Gas Turbine and Diesel | 2 |
| | 1,416 |
| Percentage of Total Energy Supply | 21% |

# Island Energy Planning

**Demand growth, grid stability/security and industrial marketing strategies require enhanced on-island grid capacity soon.**

**Kyoto compliance, tax benefits, supply security and cost of energy to the consumer are other key factors of immediate concern.**

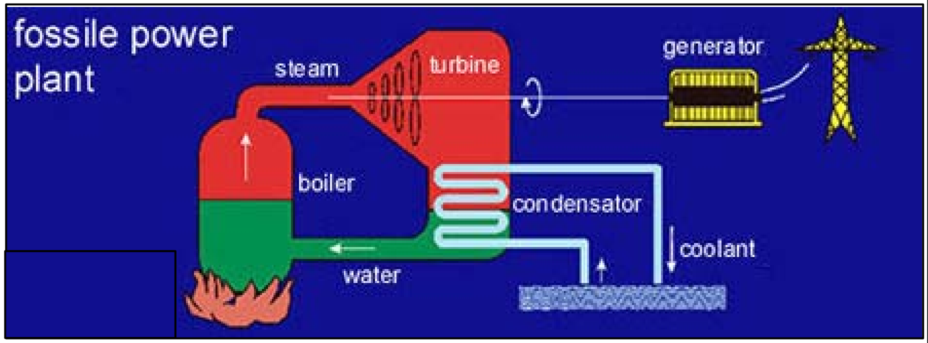
**Depreciation of existing thermal facilities is high.**

# New Island Electrical Capacity Options

1. Oil-based thermal.
2. HVDC Hydro infeed from Labrador.
3. On-Island Hydro procurement.
4. Wind power.
5. Nuclear fission.
6. Natural Gas-based thermal.

## 1 - Oil-fired generation

Oil based thermal presently provides the Island with seasonal power capacity. The primary facility at Holyrood is ageing, our dependence upon foreign oil (No. 6 fuel, 2.2%sulfur) has never been greater, the pressures to decrease greenhouse gas emissions and pollutants are increasing and the cost advantage of oil vs. other energy sources is dwindling.




NOTES:

Holyrood was placed in service in 1970 with two 150 MW units. A third 150 MW unit was added in 1980 to increase the output to 450 MW. In 1988/89 the original two units were modified to increase the plant capacity to 490 MW

Estimated Service life Holyrood thermal plant 25 to 30 years

Annually the plant generates 3000 GWh of energy which can be up to 40 percent of the Islands energy requirements.

The plant burns No. 6 residual fuel oil at the rate of approximately 6,000 barrels per day, or 2 million barrels per year. This amount of fuel is equivalent to the amount of fuel to run 200,000 cars over 15,000 km each (about every drop of gas in Newfoundland) – but the fuel oil is much dirtier.

We pay between $80 and $100 million per year for the fuel at Holyrood depending on demand and rainfall. We have not begun to pay for the recent jump in oil costs above $39/barrel. A switch to cleaner fuel from 2% to 1% sulfur will add 10% more to this cost.

Source: NL Hydro Annual report 2005

## 2 - Labrador Hydro Power

Sell Labrador hydro power at a premium as peaking power to large utilities where thermal and nuclear plants suitably provide base load supply. Resource is worth more to NL this way. Install more generating capacity at the upper Churchill plant – develop the lower Churchill to handle higher discharge rates. Isolated grid stability requires spinning backup capacity for unscheduled downtime of large sources. We are better served by smaller generation facilities distributed strategically on the grid.

NOTES:

The most recent cost estimate for a HVDC power line from Labrador to the Avalon is over $2 billion.

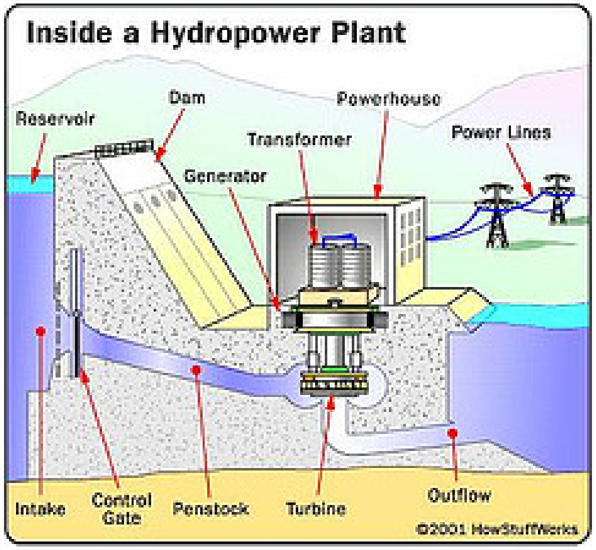
The grid would require a backup for this source as a disruption must be planned for.

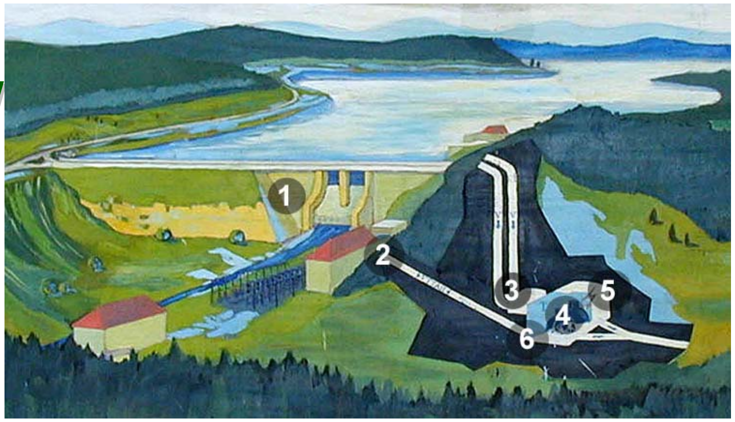
The mortgage on the power line alone – not the construction of plant ($10 billion++?) or purchase of the power – ***just the powerline*** would be $10-$20 million per month depending on interest rates.

If Newfoundland electricity customers have to pay for this powerline then we will all have an increase in our ***monthly*** bill of well over $100 – for decades to come.

## 3 – On-Island Hydro Procurement:

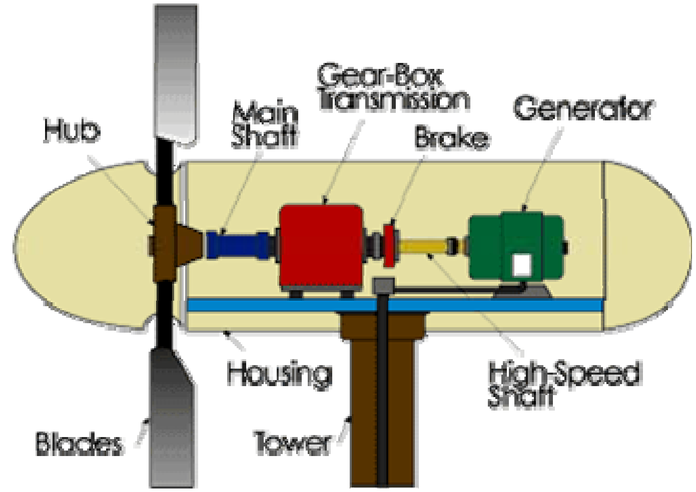
Allow/promote non-utility generators to add mini, micro and small hydro capacity (say up to 25 MW) to the grid via new developments and retrofitting existing facilities. Stringent regulations should be enforced and competition promoted, general sales and permitting guidelines established. End the moratorium – it is not rational.




## 4 - Wind Power

NL should promote private wind power developments by fixing guidelines for energy sales to the distribution utilities. Wind power is best as a fossil fuel-offsetting energy supply when hydro storage is available. It is not effective as firm capacity nor does it contribute positively to grid stabilization. It is not a substitute for demand-ready capacity.




NOTES:

Wind Power in Newfoundland:

*In 2004 September, NLHydro started purchasing power from Ramea wind – 6 x 65 kw turbines capable of providing 35% of capacity – estimates that 190,000 litres of diesel will be displaced annually.*

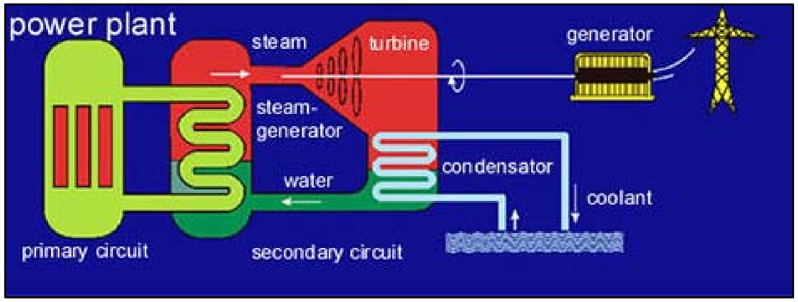
*In a February 2005 WIND backgrounder – NLHydro says Ramea wind provides 15-20% of energy needs of Ramea*

*In the NLHydro 2005 annual report : Ramea wind provided 418,000 kWh = 10% of energy requirement of Ramea or 107,000 litres of diesel*

*This suggests a capacity factor for4 Ramea Wind of **12%***

Even if better efficiencies are realized The island system “can only accommodate up to approximately 80 MW of wind power without significant risk of spilling water at our existing hydroelectric stations” – NLHydro = 15% of thermal capacity.

# 5 - Nuclear power




Nuclear power is re-emerging as primary clean base-load energy supply for large interconnected grids. Present design strategies do not provide for small units, facilities are measured in the 1000's of megawatts. This single source (non-distributed) generation is poorly suited to an Insular grid the size of ours where hydro accounts for almost 100% of energy needs for part of the year.

# 6 - Natural Gas Fired Generation

*Today*, the CCG equivalent of 2600MW of power is produced in associated natural gas at Hibernia and White Rose - greater than the entire capacity of Island generation, greater than the prospective capacity of the lower Churchill, and the natural gas is much, much closer to us than Labrador.

Even if only 60% recoverable, the natural gas resources at Hibernia, Terra Nova and Whiterose can provide fuel to run a Holyrood-equivalent combined cycle plant at full capacity 365 days a year for over 100 years.

## 6 - Natural Gas Fired Generation Cont…

Converting Holyrood from Residual Fuel oil to Natural Gas would reduce Provincial CO2 and SO2 emissions by 480,000 tonnes per year ( meeting the one-ton-challenge for every Newfoundlander – indefinitely)

*Associated* natural gas can be piped to NL at a significantly lower cost than a power line from Labrador and could arrive a decade earlier with all infrastructure paid for prior to the start up of a Lower Churchill river power plant, i.e., on the grid in a short enough time frame to be of use to Abitibi, INCO and other current industrial consumers.

# New Electrical Capacity Options CONCLUSION:

Thermal power from fossil fuels will continue to play a major role (30%++) in meeting electrical energy needs on the Island of Newfoundland for many years to come. Options are (coal not considered):

- Foreign oil-fired generation
- Domestic oil-fired generation
- Foreign natural gas-fired generation (LNG import)
- Domestic natural gas-fired

*It is my assertion that the best solution economically, technically environmentally and politically is domestic natural gas fired generation, 2nd place = LNG*

## Natural Gas Development Hurdles

Rules, regulations, taxation . . Framework needs to be in place, clear and enforceable to attract investment and encourage timely development.

Oil and gas operators need to be in competition with each other, they don’t always work well together.

Operators have limited time horizon – long term planning strategy is often vague, giving way to shorter term shareholder demands. They do not like to interfere with profitable operations.

Perceived risks from icebergs, and harsh ocean environment

## Development Hurdles Continued. . .

Labrador gas, tanker-based production/transport are distracting decision-makers, regulators, academics and the public from developing Grand Banks gas resources now.

Reinjection issues. Reinjection of gas is not essential for reservoir maintenance – and retrieval is not guaranteed (permanent losses may be anywhere between 10 and 50%).

Gas will ultimately be produced commercially on the Grand Banks but Newfoundland may be bypassed.

## Natural Gas Development Criteria

- Market driven, not concept driven.
- Proven recoverable resource-based
- Lowest technological risk
- Lowest cost, highest present value and long term
- Highest benefit to NL

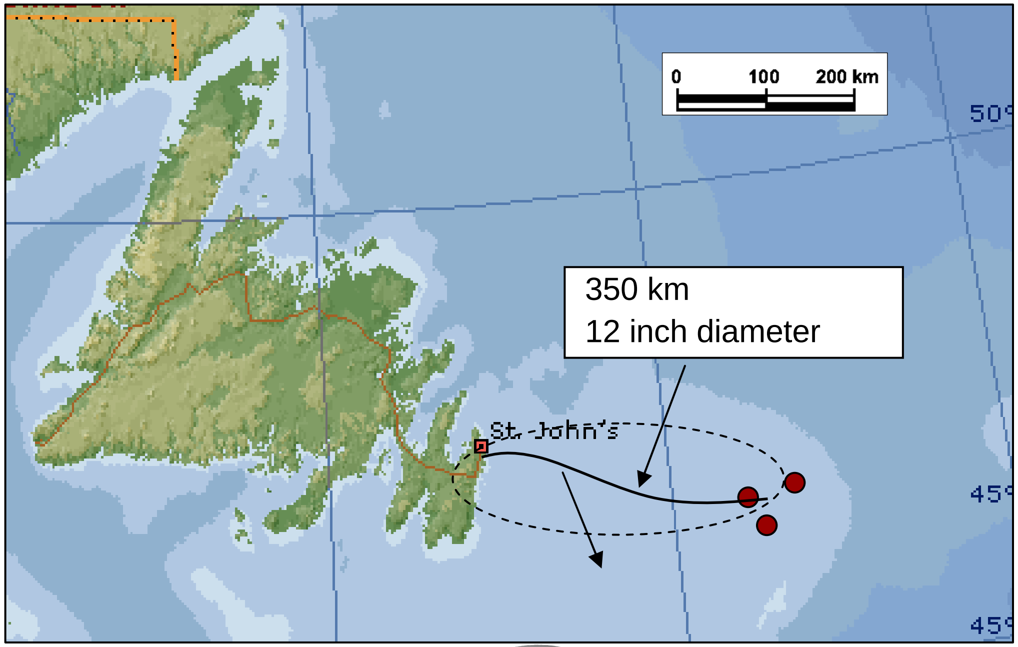
***Equals a pipeline now. . .***

## CONCEPT AVALON PIPELINE OVERVIEW:

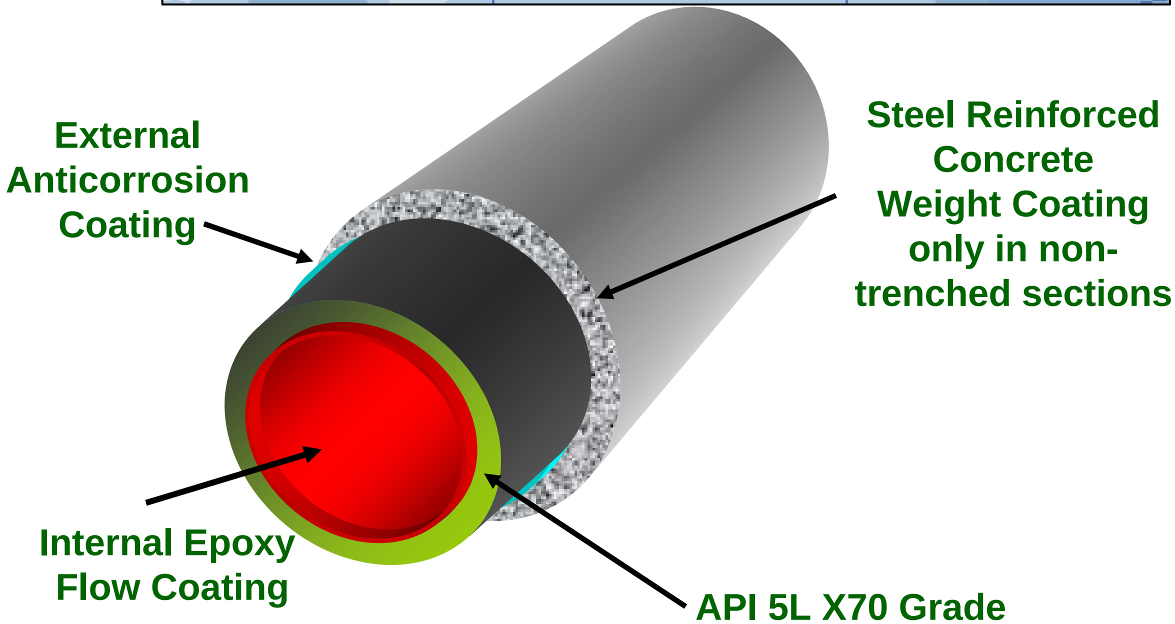
- Specifications for meeting domestic energy needs
- How to Install
- How to Repair
- How to Maintain
- Cost of this Pipeline
- Examples of Similar Pipelines

# Small Scale Avalon Pipeline Concept:

- 12” diameter pipeline 350km
- ½” wall thickness
- 3000psi inlet pressure
- 90 mmscf/d (= 600MW new Siemens CCG)




Pulled through existing J-Tube at Hibernia, trenched, bermed, reeled or laid, coated, anodes, labour, engineering, contingencies etc etc



# Pipe Lay Method

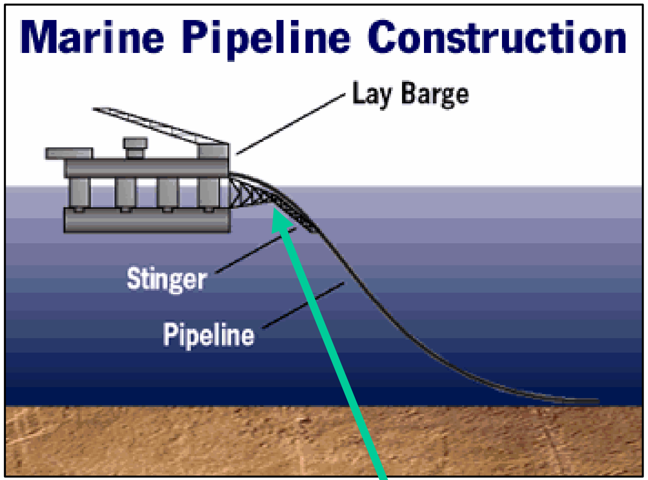
SEMISUBMERSIBLE PIPELAY VESSEL

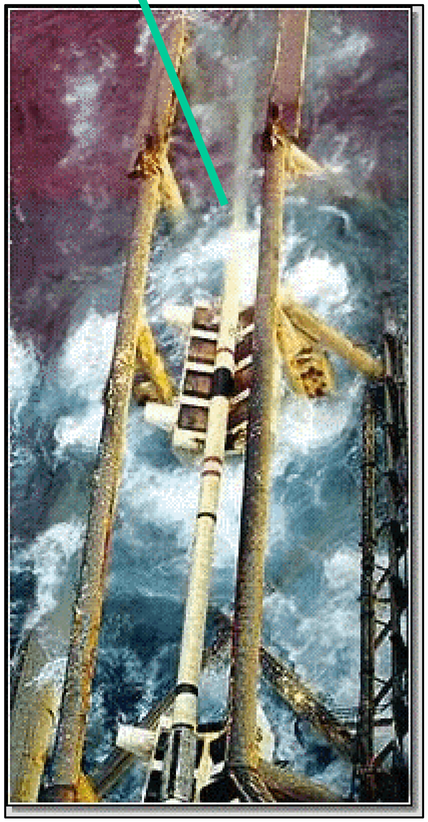
DP PIPELAY VESSEL


# Pipe-Reel Method

# Pipeline Assembly Onboard Pipelay Vessel

# Pipeline Installation Stinger



# Pipeline Prep Yard (if required)

Shaw & Shaw pipecoating facility at Sheet Harbour, Nova Scotia

EXTERNAL INSPECTION:

Via Remotely Operated Vehicle (ROV)

INTERNAL INSPECTION:

Via Intelligent pigging

## Pipeline Cleaning:

Cleaning pig train including the use of bi-directional pigs and solvent swab

# Pipeline Repair Protocol

1 Leak detection and compressor shut down

2 Damage location

3 Excavate pipe

4 Remove concrete

5 Cold-cut pipe ends

6 Insert pipeline plugs

7 Deploy hyperbaric chamber

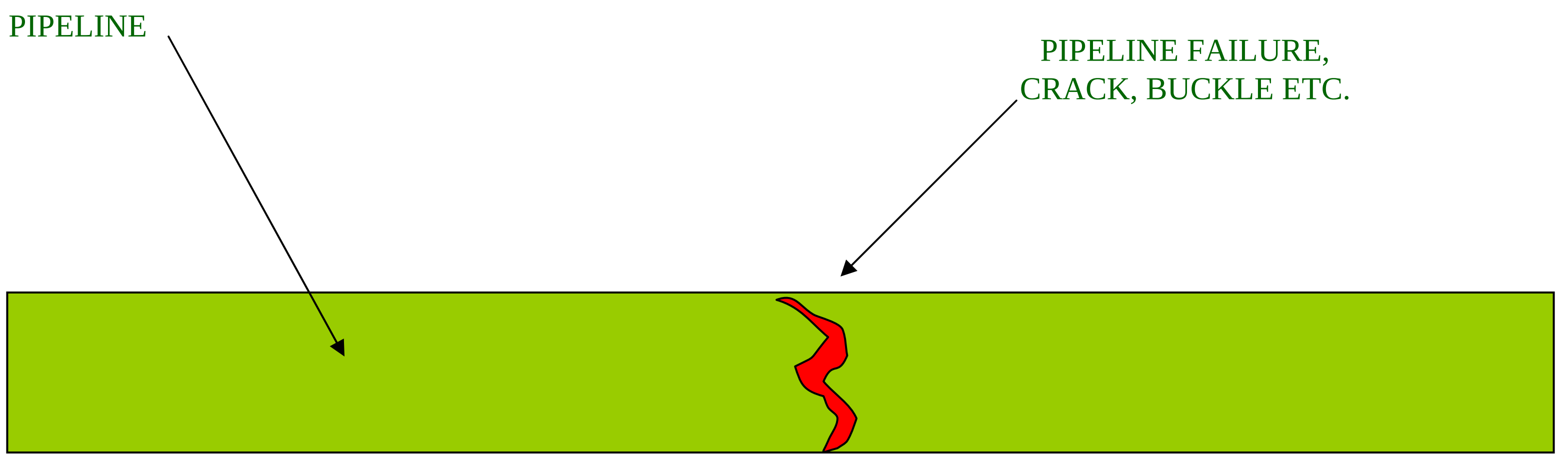
8 Perform hyperbaric repair welding

9 Repair coating

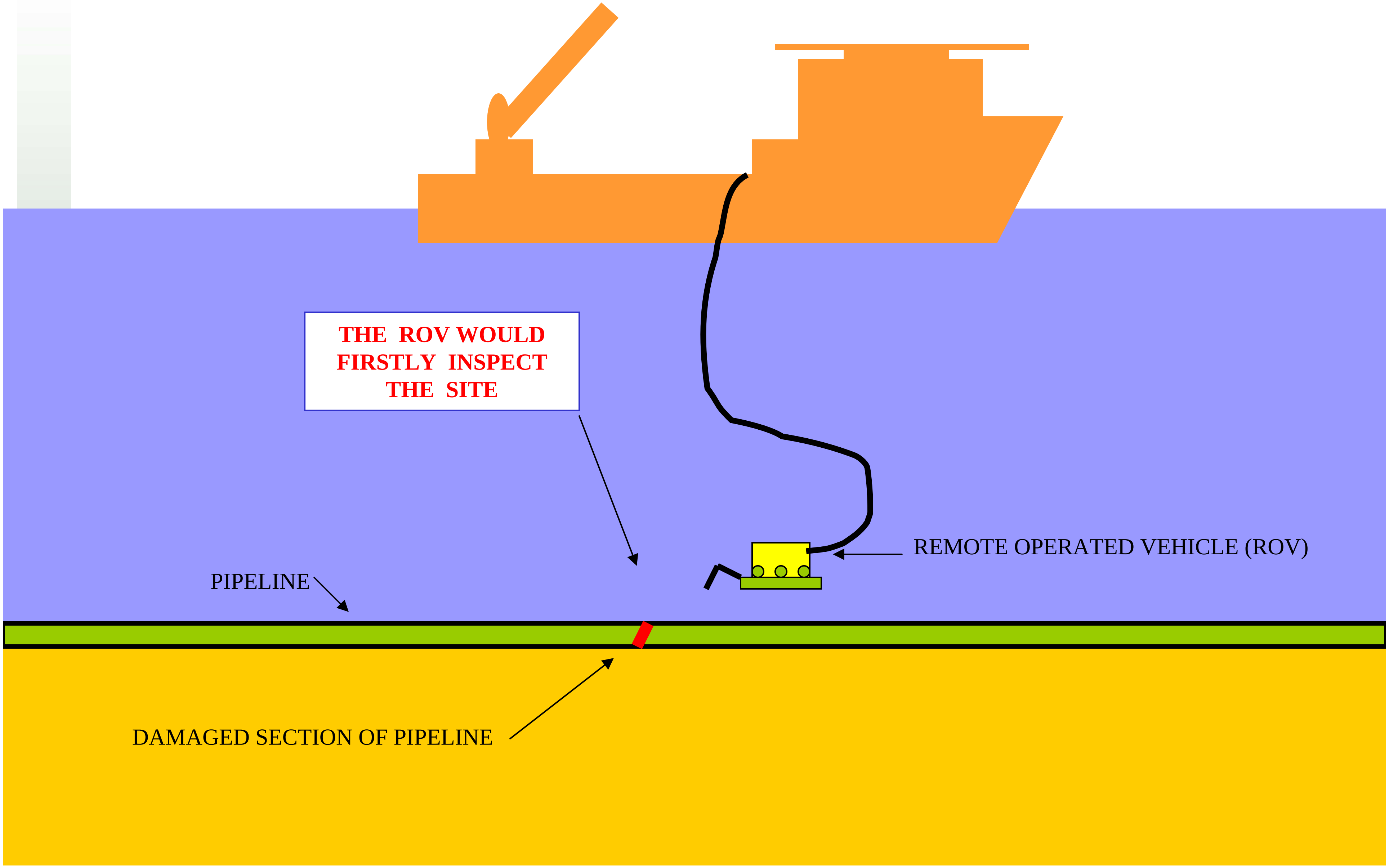
10 Recommission pipeline

# REPAIR OF A DAMAGED SECTION OF PIPELINE AT 250 m WATER DEPTH USING A HYPERBARIC WELDING SYSTEM FROM A DP- DSV

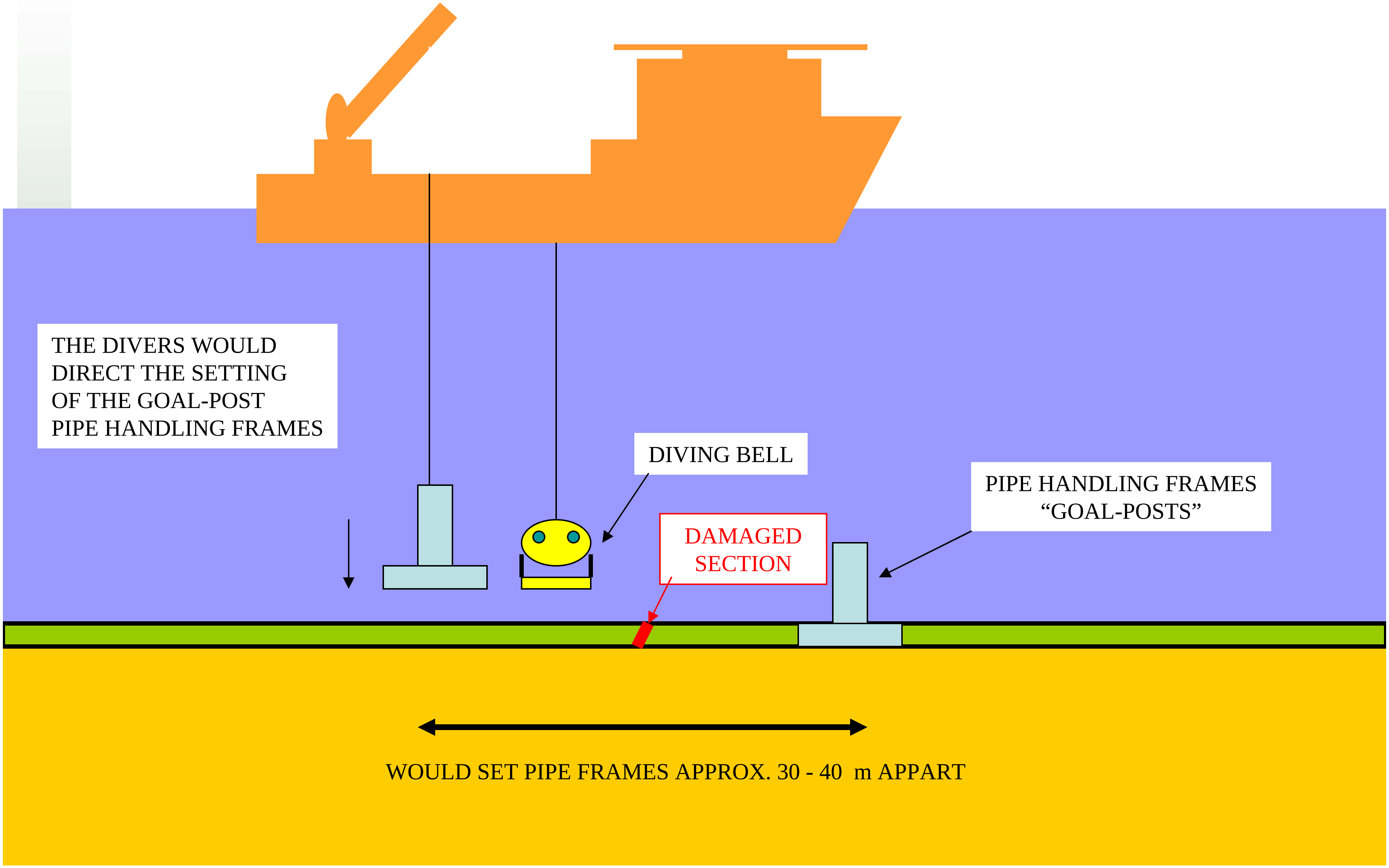
(From: Wilson, German, Bruneau, 1999)



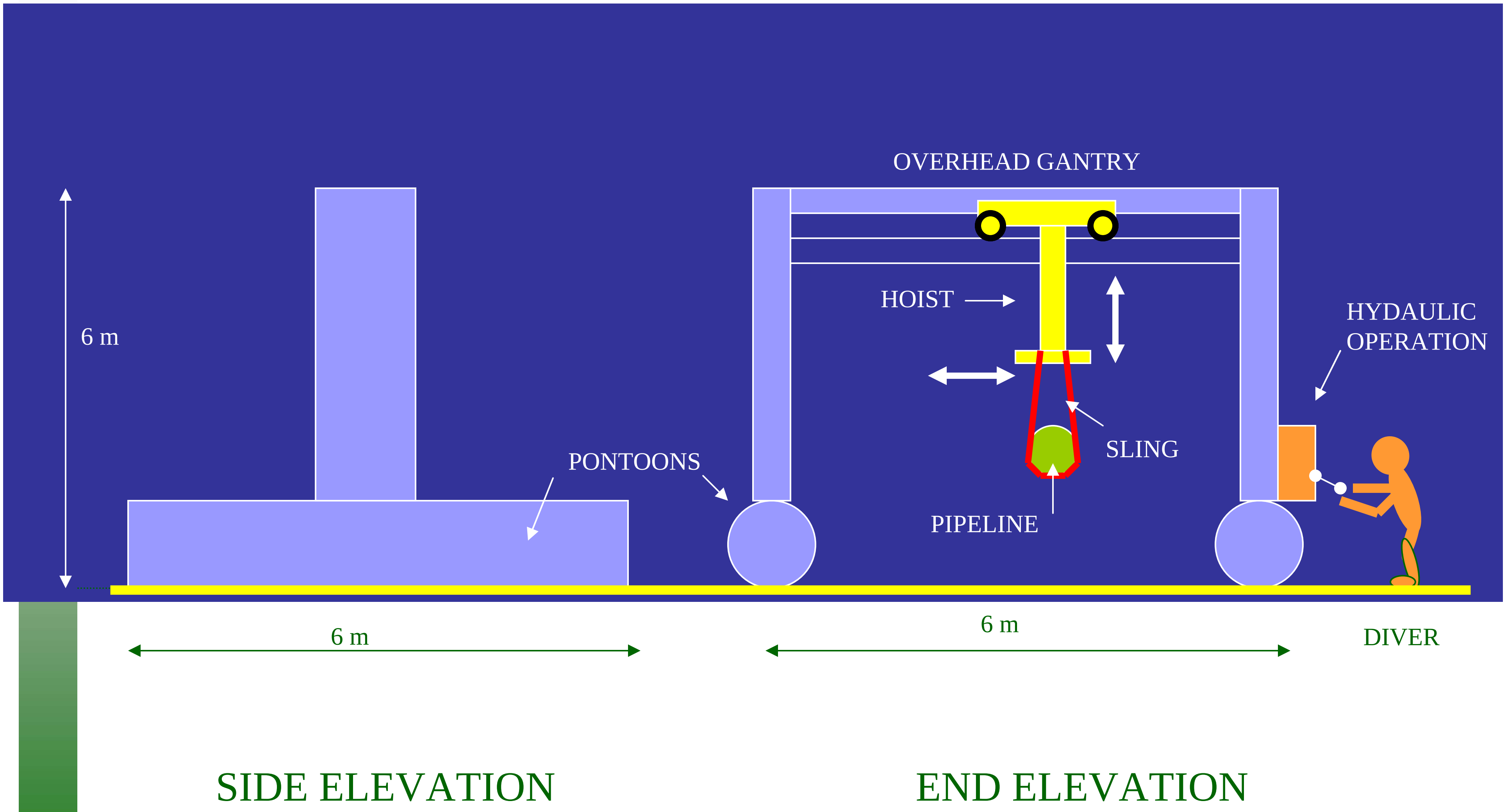
# Once the pipeline pressure has been controlled a DP-DSV would mobilise to site



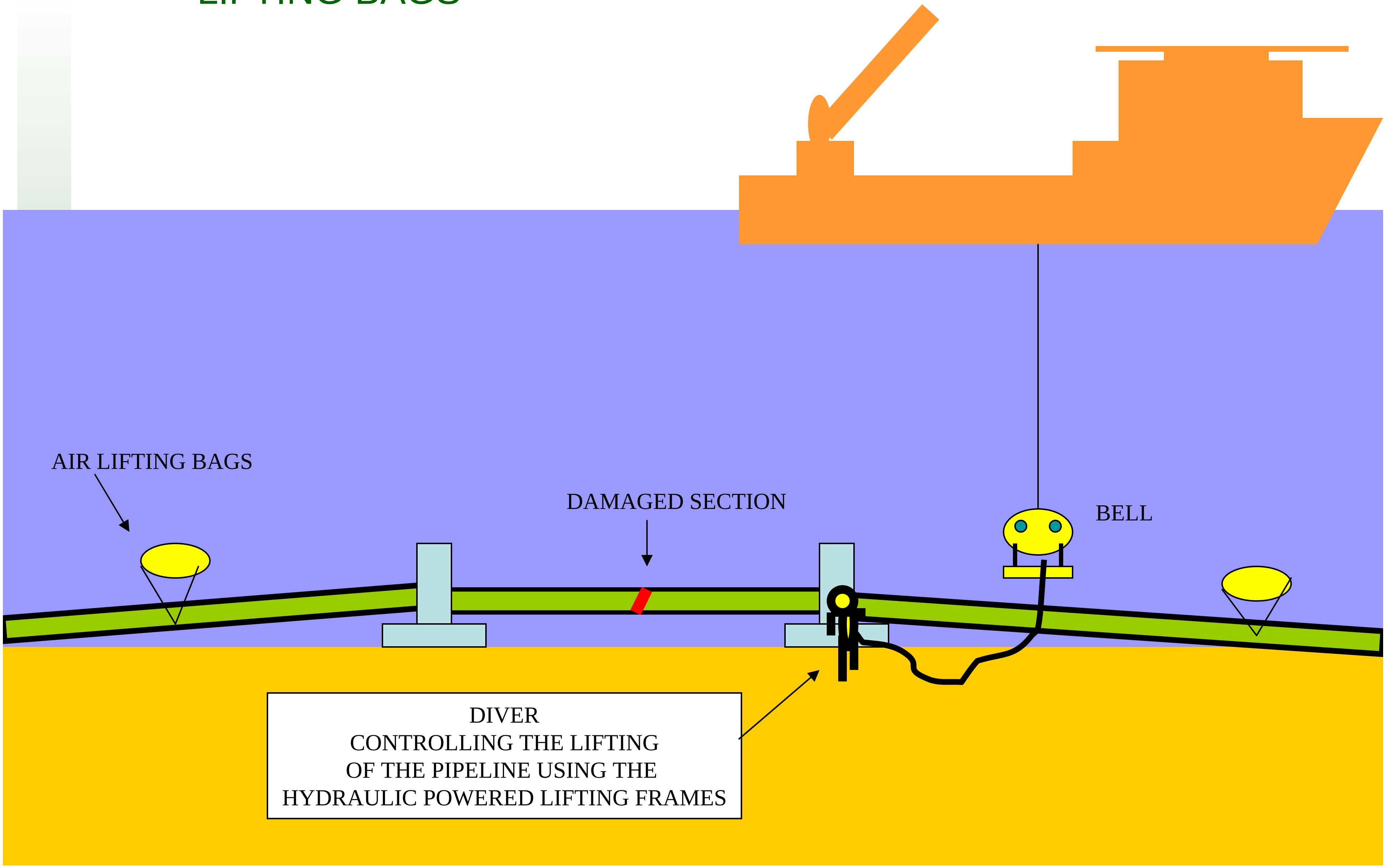
# SETTING OF THE PIPE HANDLING FRAMES



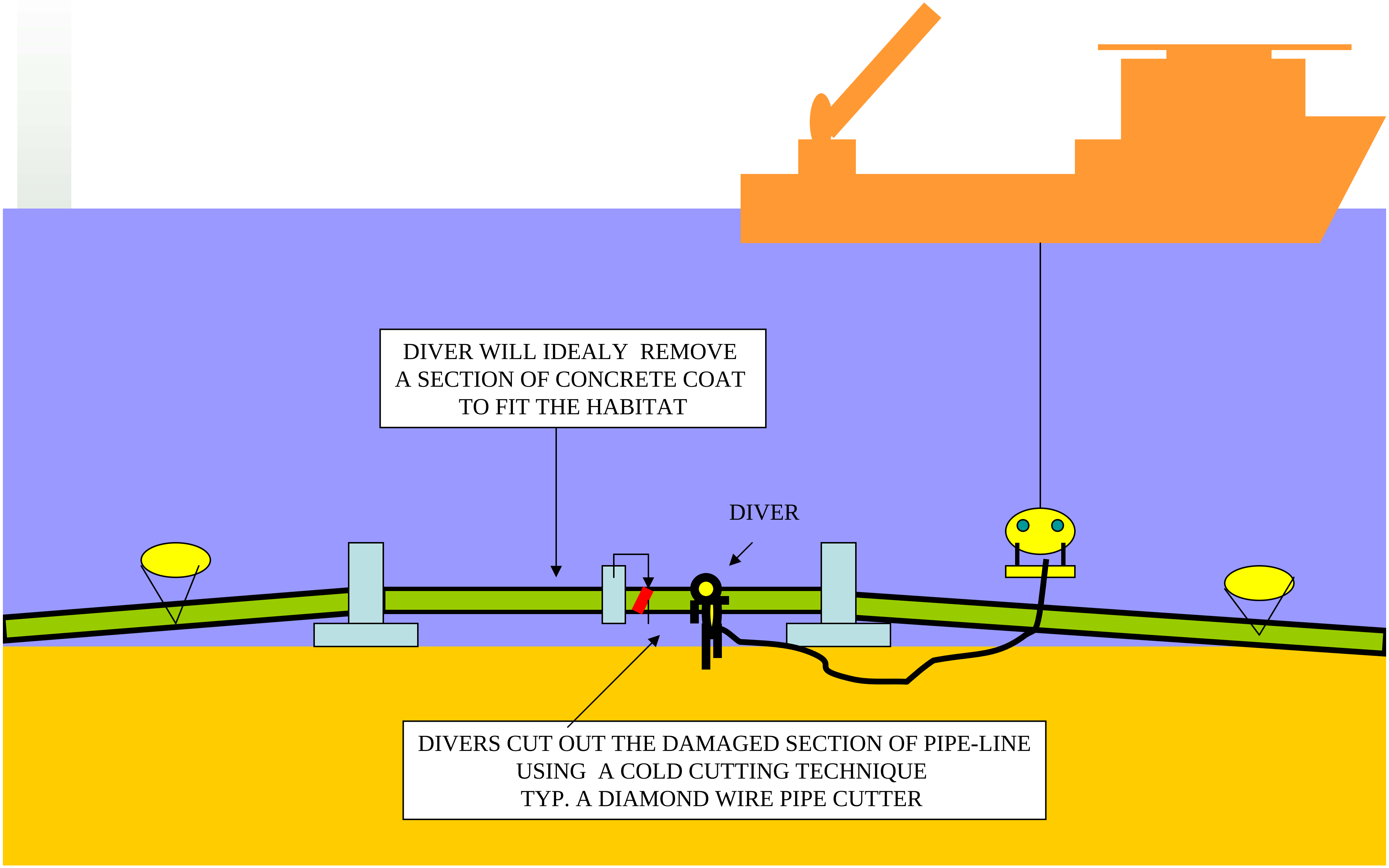
# Typical “goal-post” pipe lifting frames



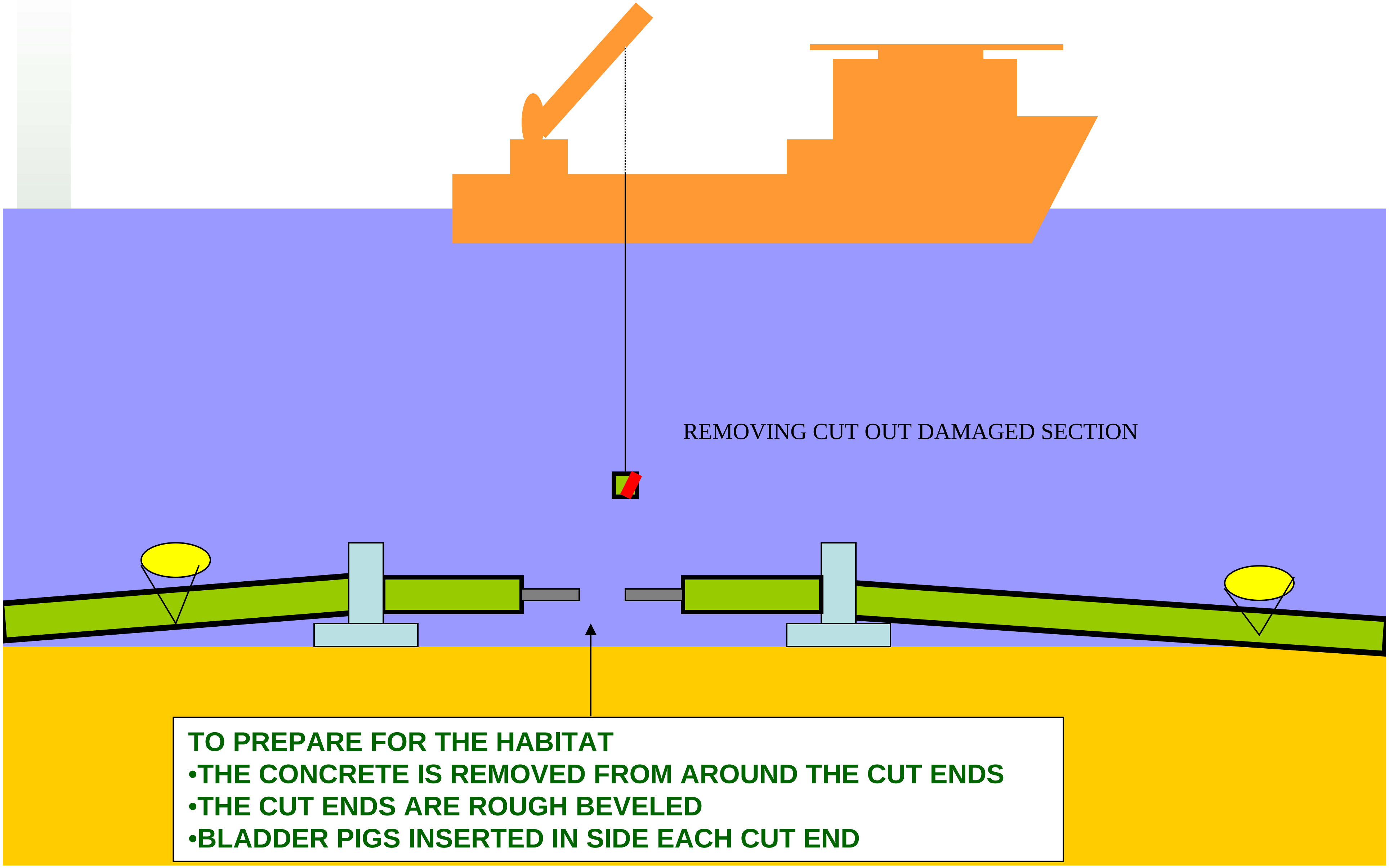
# DIVERS RAISE THE PIPELINE SECTION OFF SEABED USING COMBINATION OF LIFTING FRAME AND AIR LIFTING BAGS



# Divers cut out the damaged section of pipe

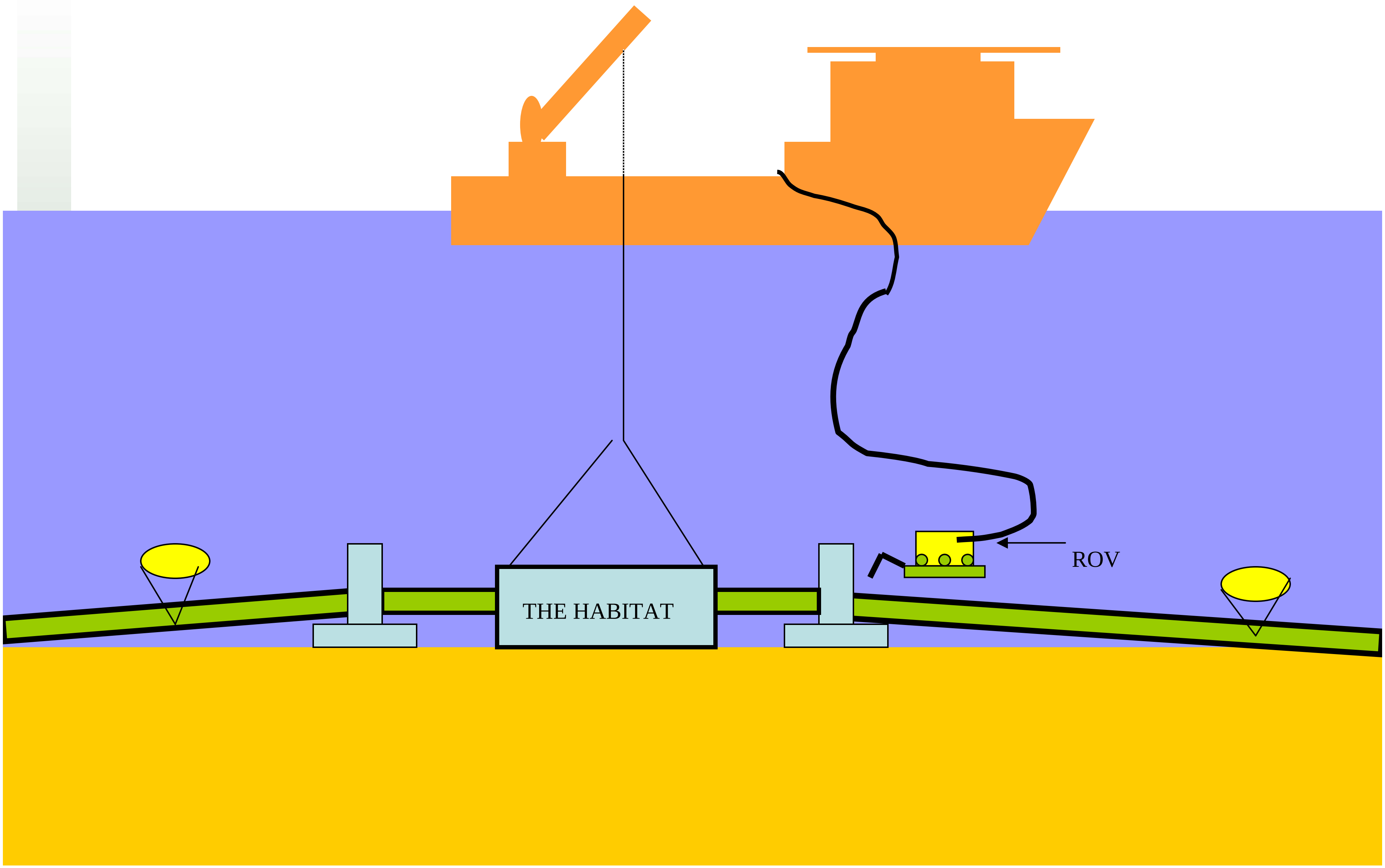


# PREPARING THE PIPE FOR PLACEMENT OF HABITAT

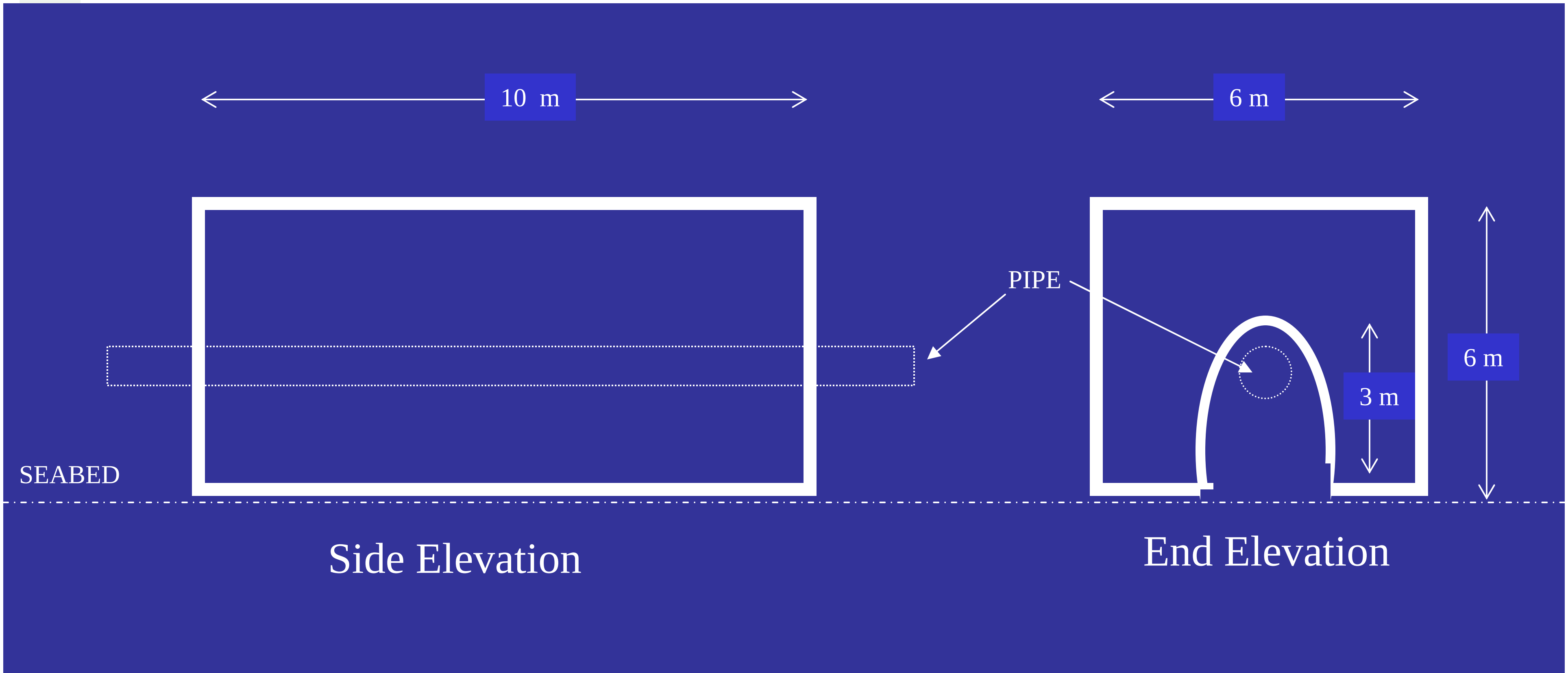



**TO PREPARE FOR THE HABITAT**
- **THE CONCRETE IS REMOVED FROM AROUND THE CUT ENDS**
- **THE CUT ENDS ARE ROUGH BEVELED**
- **BLADDER PIGS INSERTED IN SIDE EACH CUT END**

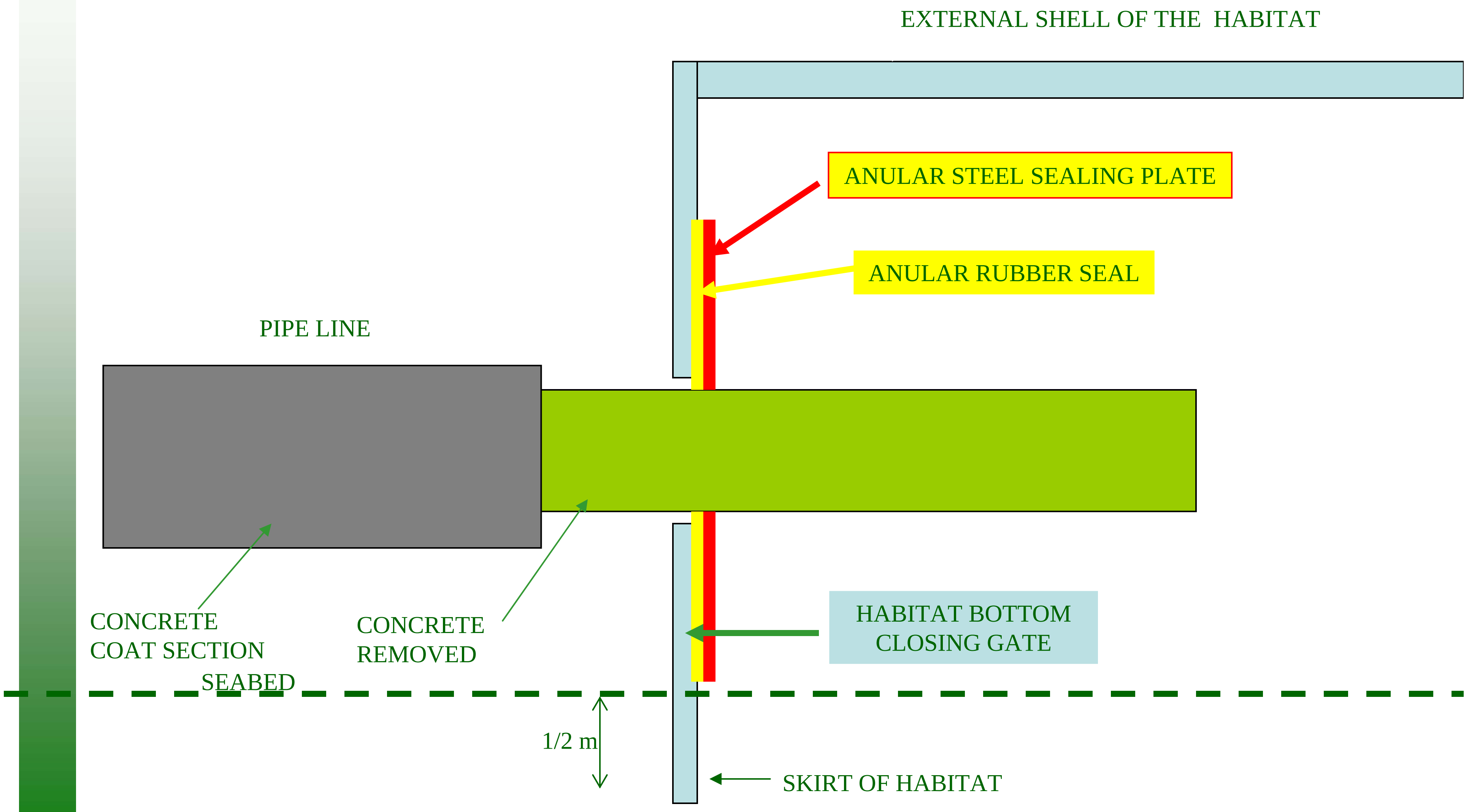
# DSV PLACES THE HABITAT



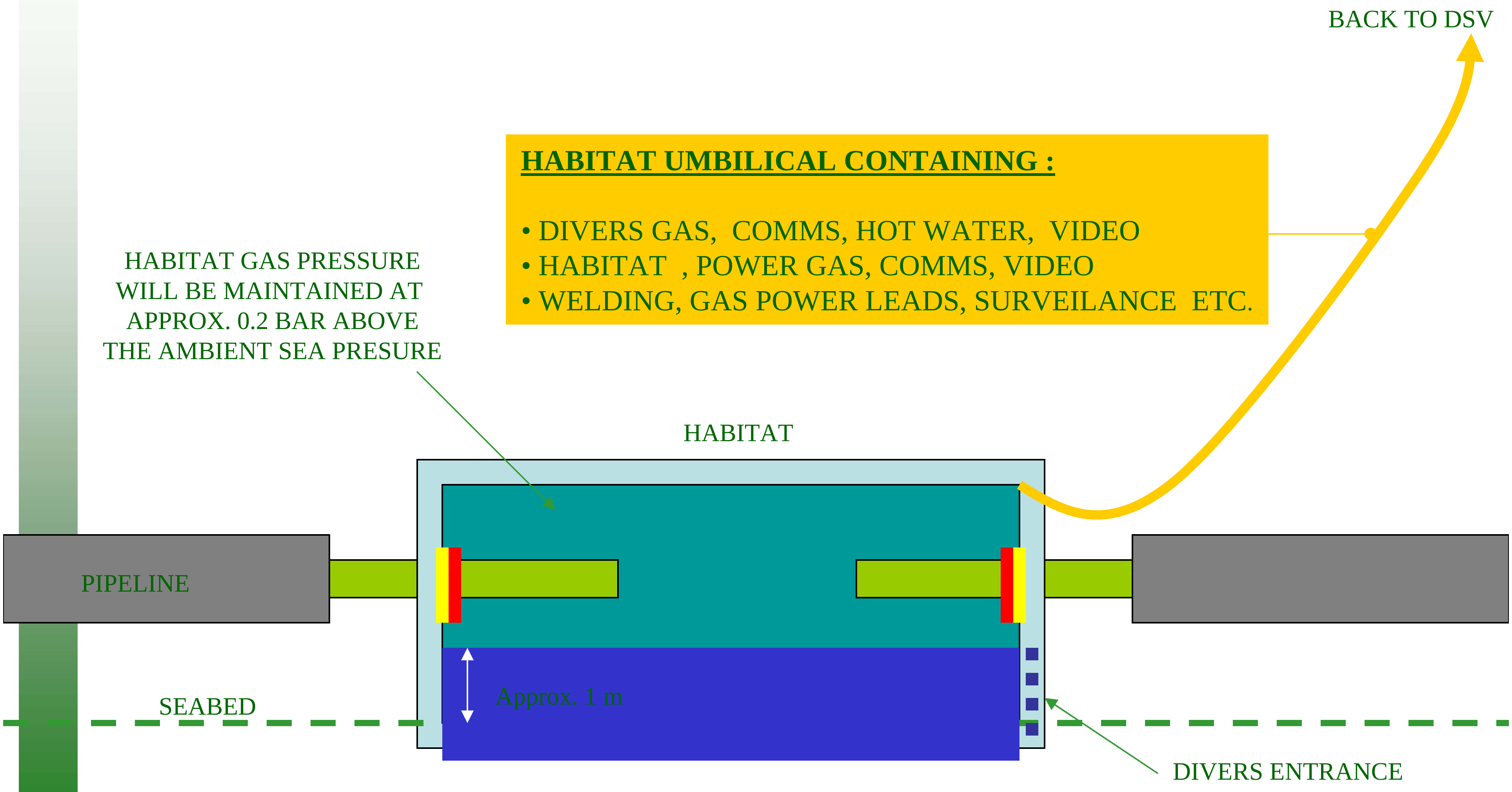
# Typical principal dimensions of a Hyperbaric Welding Habitat



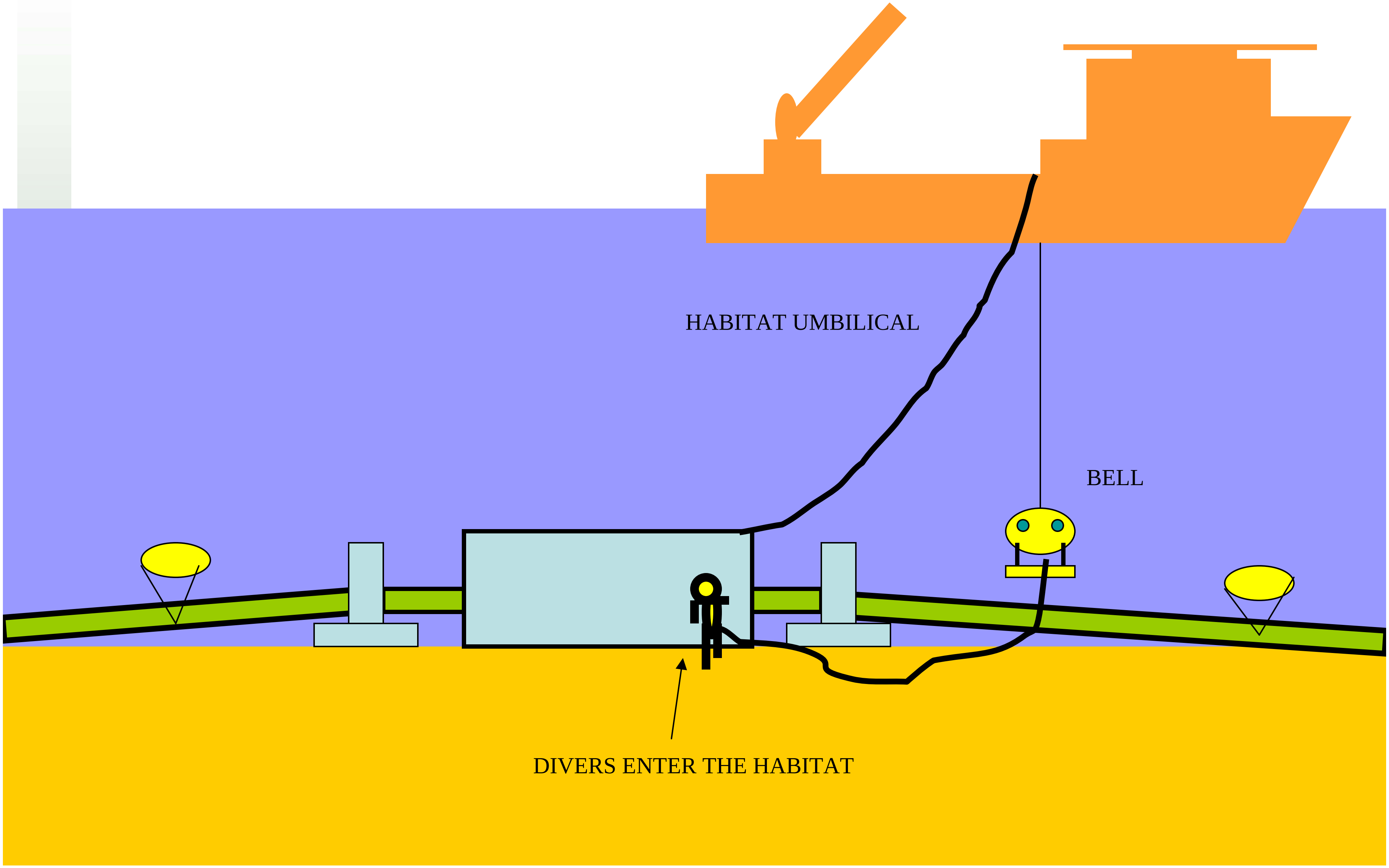
# The sealing of the pipeline inside the habitat



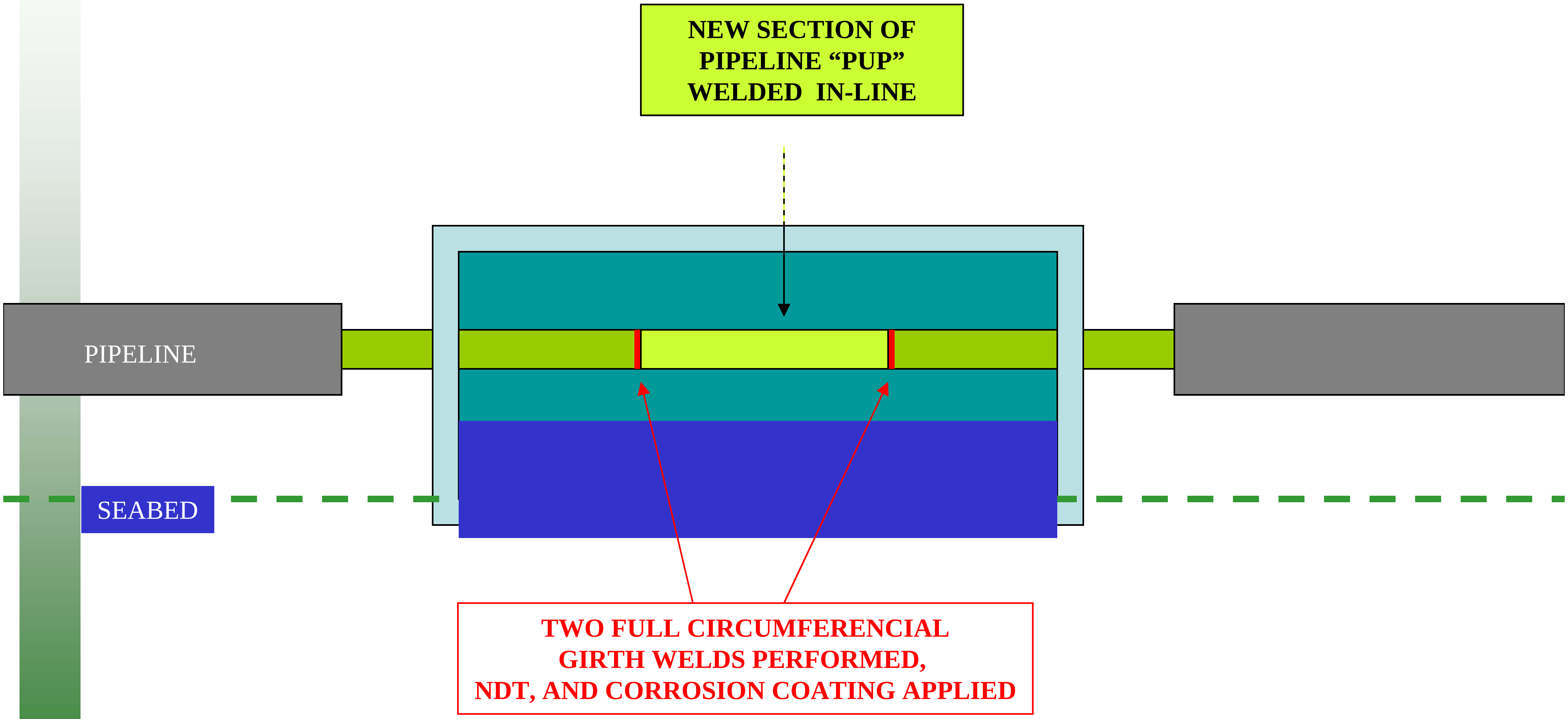
# Setting the habitat ready for work (pumping dry)



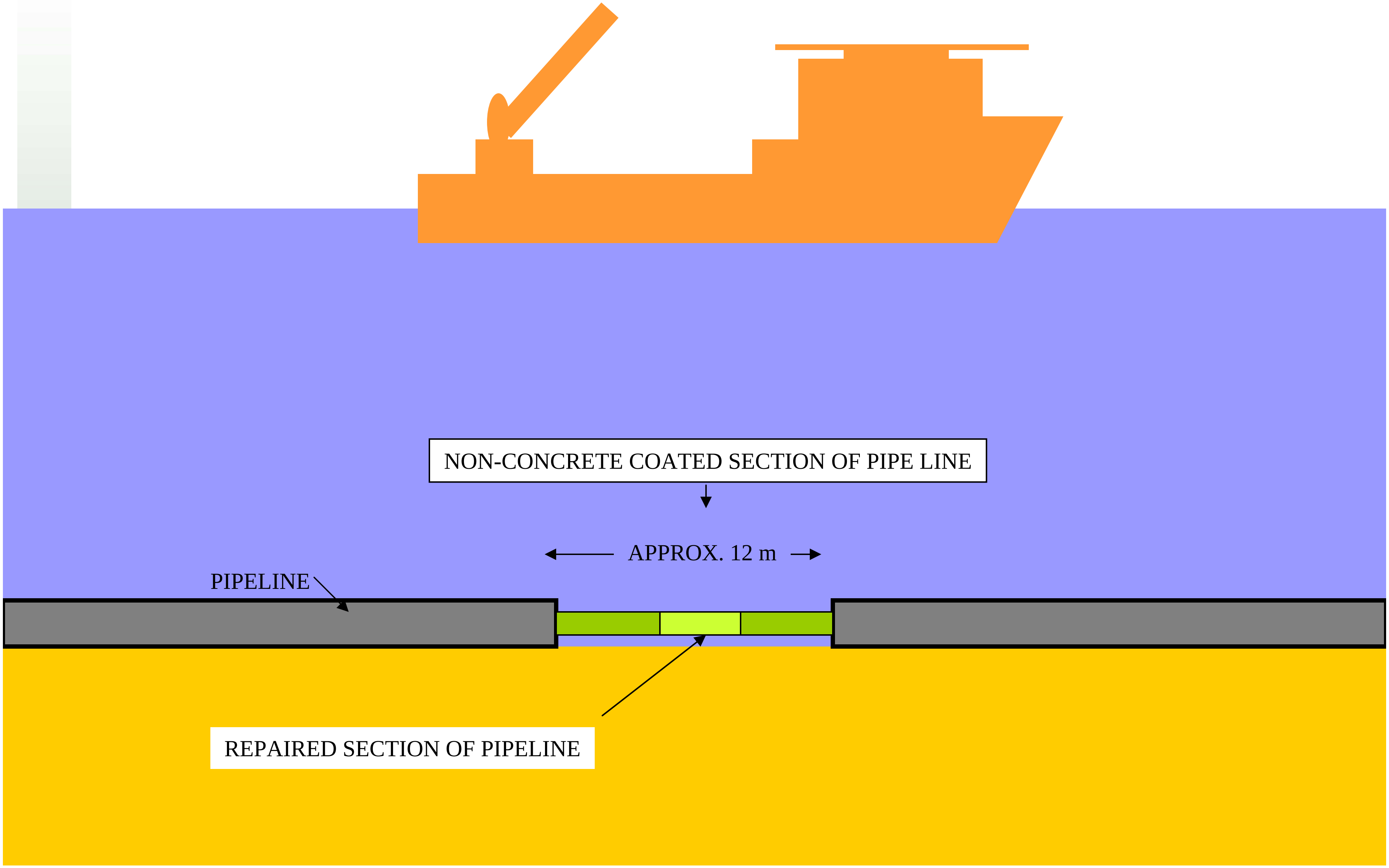
Once the habitat is set the divers set the seals, pump dry and then commence the hyperbaric weld



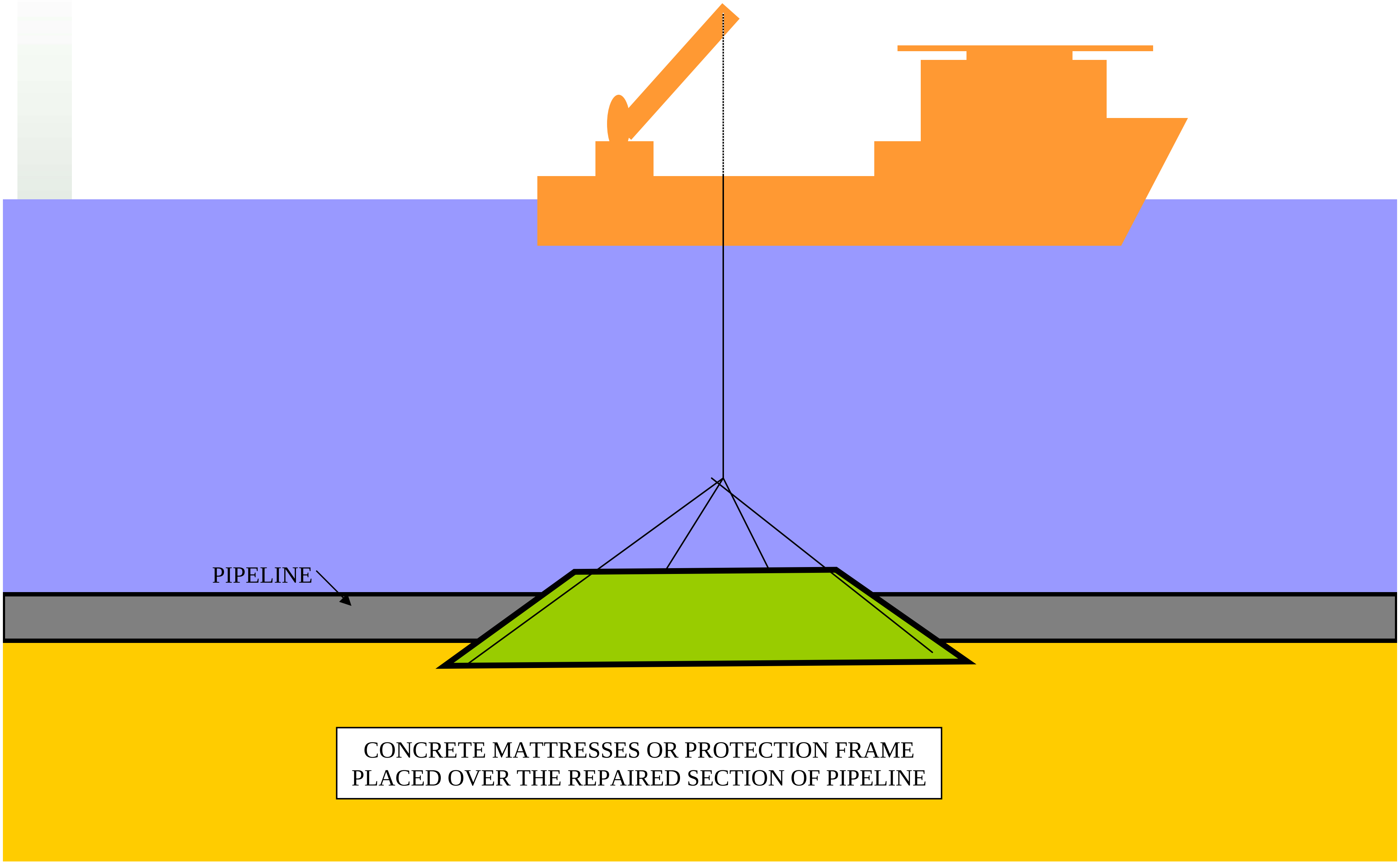
# The hyperbaric weld



## Once the pipeline has been repaired the DP-DSV would recover the hyperbaric spread

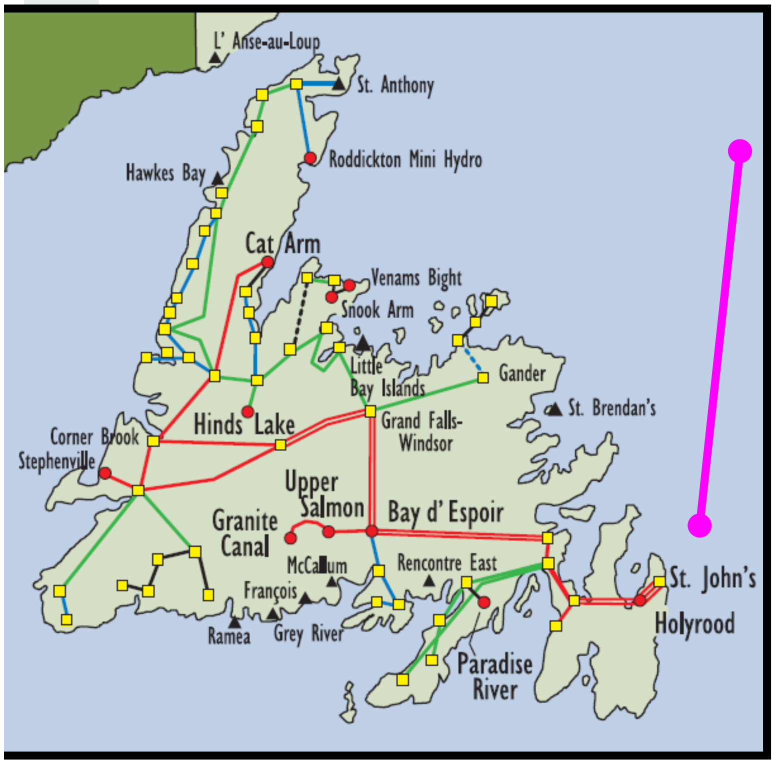


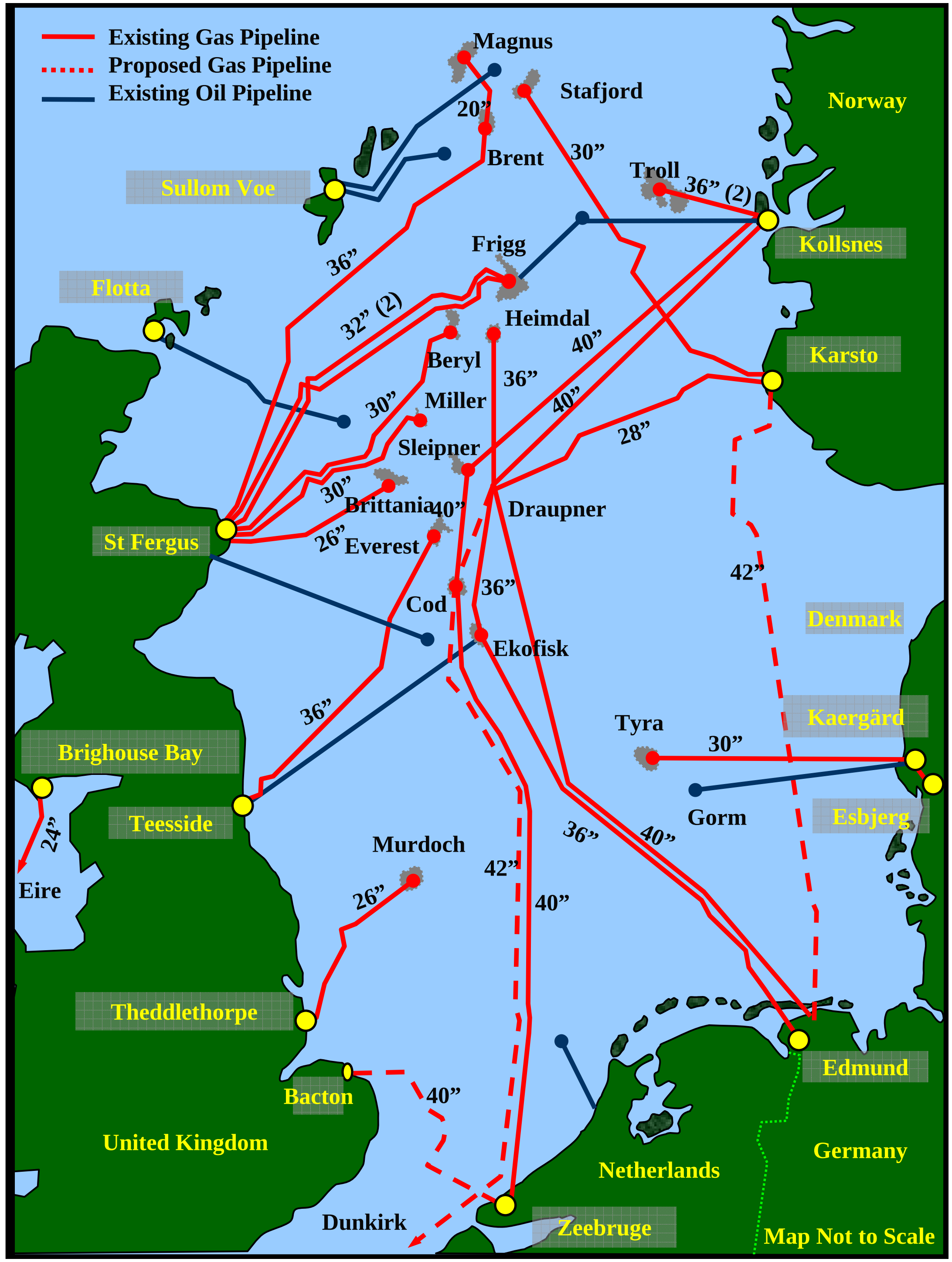
# Once the pipeline has been repaired the DP-DSV would place a protection frame or concrete mats



# OTHER PIPELINES
## Major North Sea Pipelines

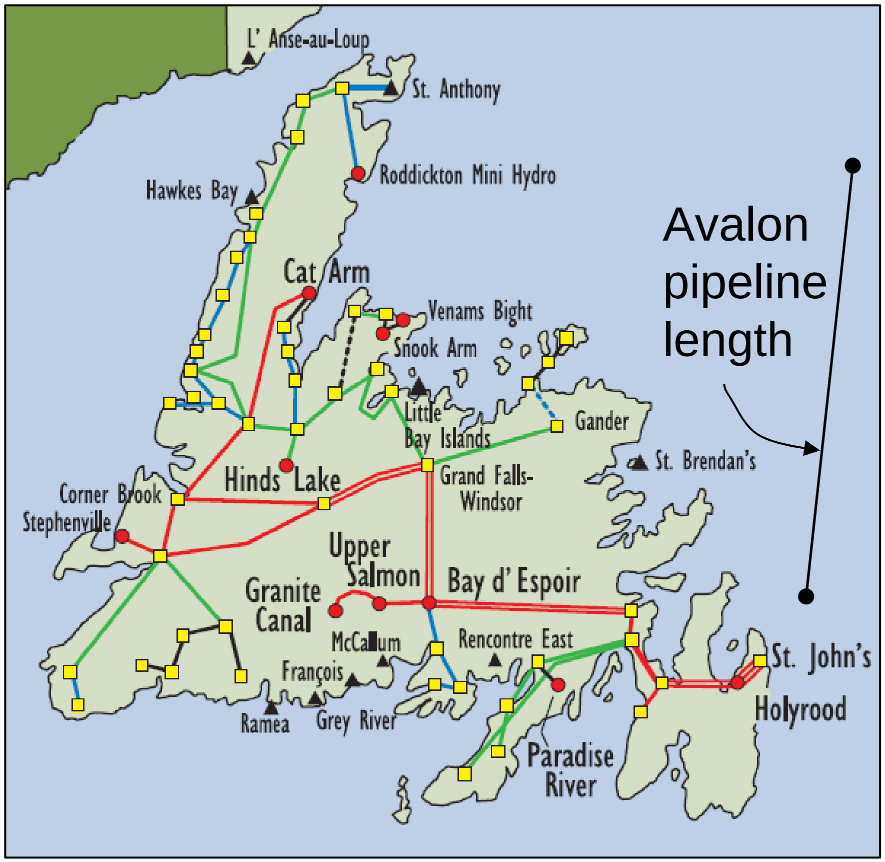
SAME SCALE

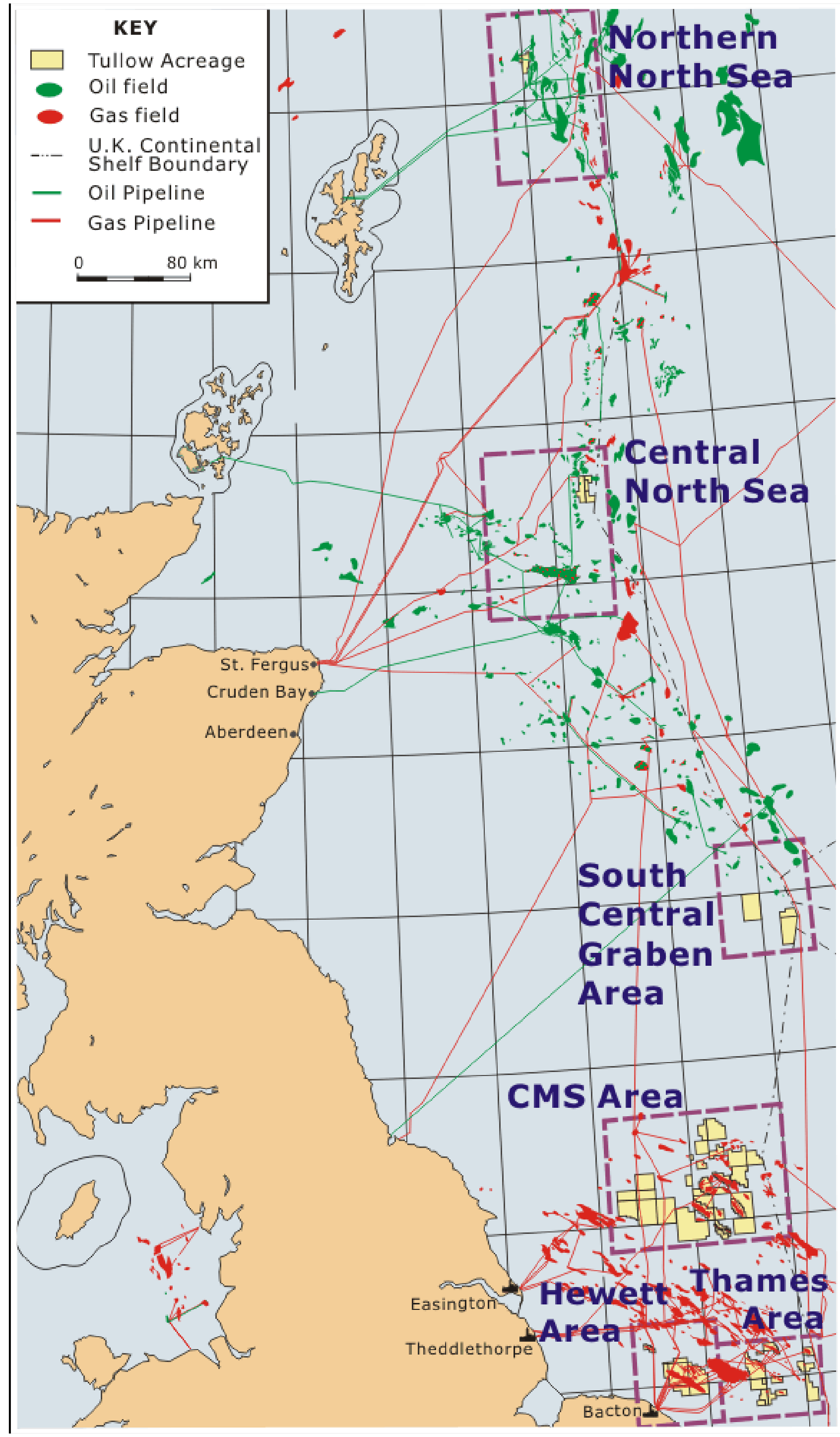


# North Sea UK sector
# Minor Pipelines

SAME SCALE

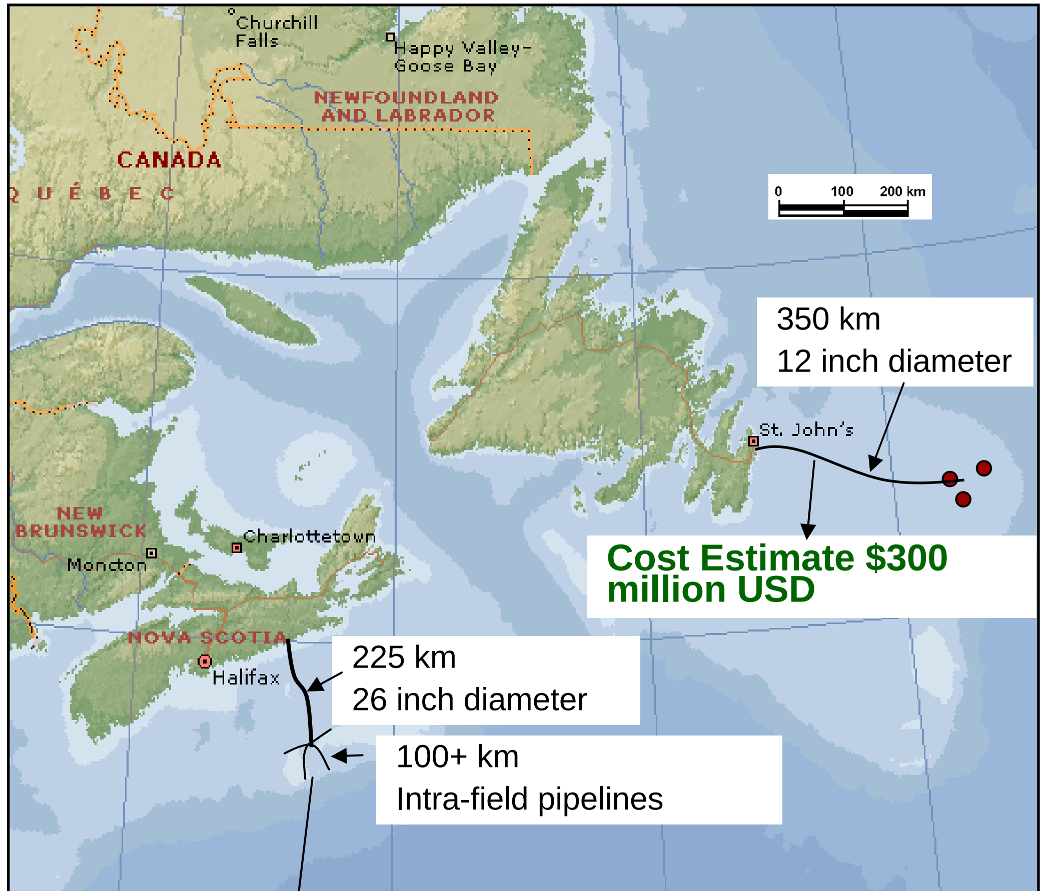


# SOEP – Sable Pipeline

Sable Gas Pipeline

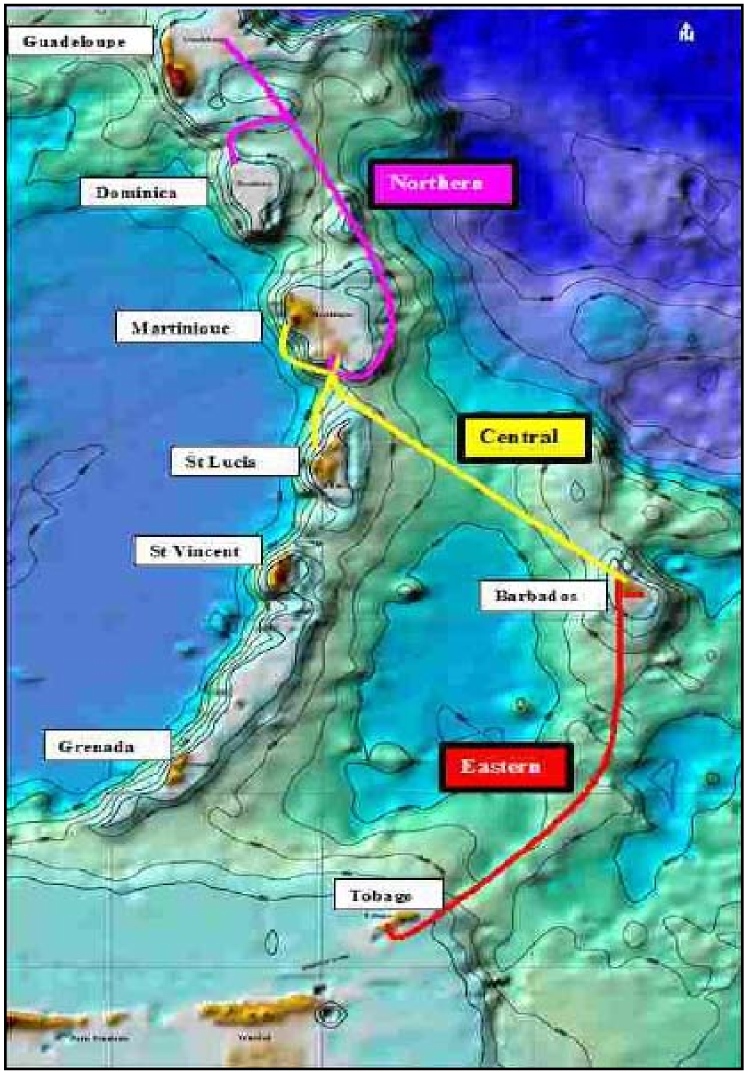
- 225 km 26 inch pipeline
- 100+ km 18 inch, 12 inch
- $250 million CAD
- 23 months to complete
- Throughput up to 500 mmscfd




**Approx $200-250 million USD to build subsea pipelines in 1999**

# Eastern Caribbean Pipeline Project

- 900-kilometre pipeline between 5 islands
- Maximum water depth 2000m
- Routing minimizes earthquake problems, hurricane wave problems, coral reefs sensitivities, volcanoes, fishery
- 12 inches, 10 inches, 8 inches
- Delivery of 150 mmscf/d
- Cost $550 million USD
- Commercially viable according to producers and contractors but not yet built due to political environment




Source: Doris Inc. Technical and Economic Feasibility of the Eastern Caribbean Gas Pipeline 2002

# Vancouver Island Pipeline 1991

Westcoast Energy, Centra, Terasen

- 550-kilometre pipeline
- Mountainous terrain and along the ocean floor
- One of the world's deepest underwater pipelines 400m+
- Twin 10 inch subsea section
- $355 million CAD
- Delivers over 100 mmscf/d
- Populatuion of Vancouver Island is 690,000


Source: Centra Gas (B.C.)

**Natural Gas and its Impacts on Greenfield Areas**

*Submitted to Atlantic Canada Petroleum Institute*

*By Gardner Pinfold Consulting Economists Limited September 2002*

# Pipeline Costs

# Pipeline Cost Details

Source : Private communic J.P.Kenny, EXXONmobil Corp., Others (2005)

| Input Data | | |
|---|---|---|
| Pipe Length | 330 | Km |
| Pipe Outer Diameter | 14 | inch |
| Pipe Wall Thickness | 0.486 | inch |
| Pipelay Rate | 4.1 | km/day |
| Trenching Rate | 2 | km/day |
| % Route Trenched | 100 | % |

**Construction**
- Survey 1
- Survey 2
- Pipelay
- DSV
- Trench
- Shore Approach
- Platform Pull In
- Pre-Commisioning

**Engineering**
- Concept Engineering
- FEED
- Detail Engineering
- Regulatory Process
- Environmental Effort

**Management**
- PMT
- Owners Costs

**Procurement**
- Line Pipe
- Line Pipe Delivery
- Anodes
- External Coating
- Internal Coating

| | | |
|---|---|---|
| | **U.S. Dollars** | **203,191** |
| Contingency | 20 % (includes Ins.,duties & contingency) | 40,638 |
| | Total Project Cost, million U.S. dollars | **243.829** |

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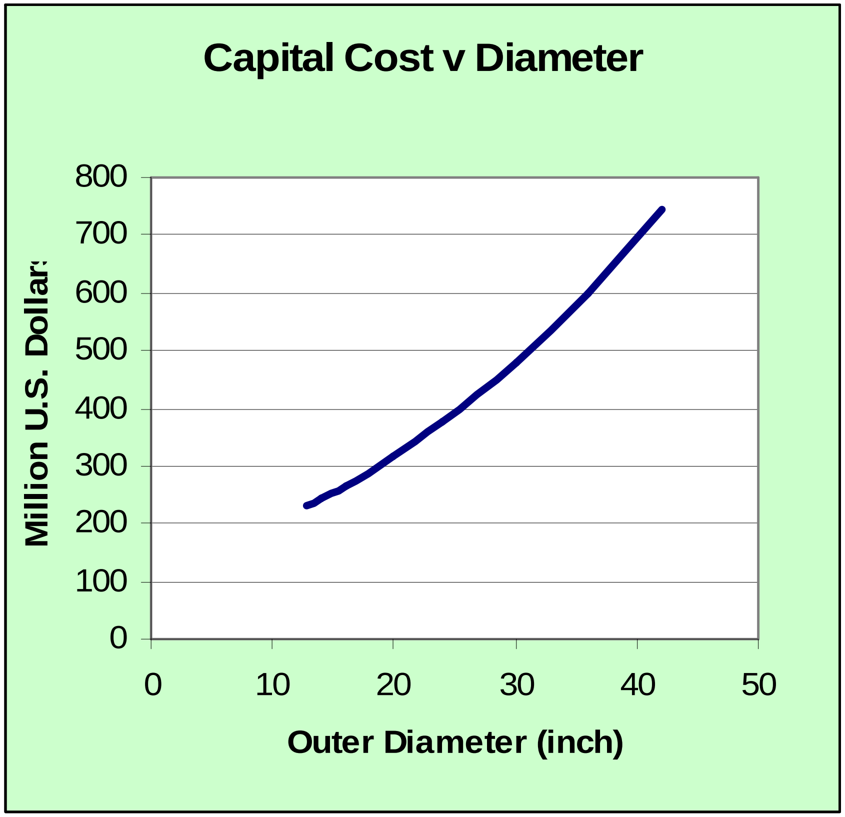
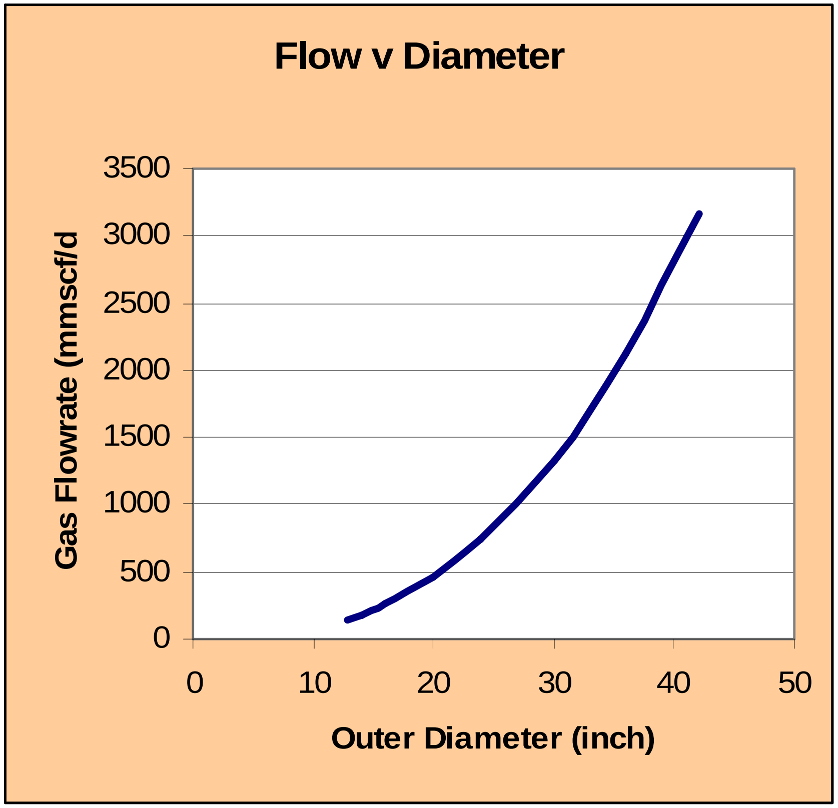
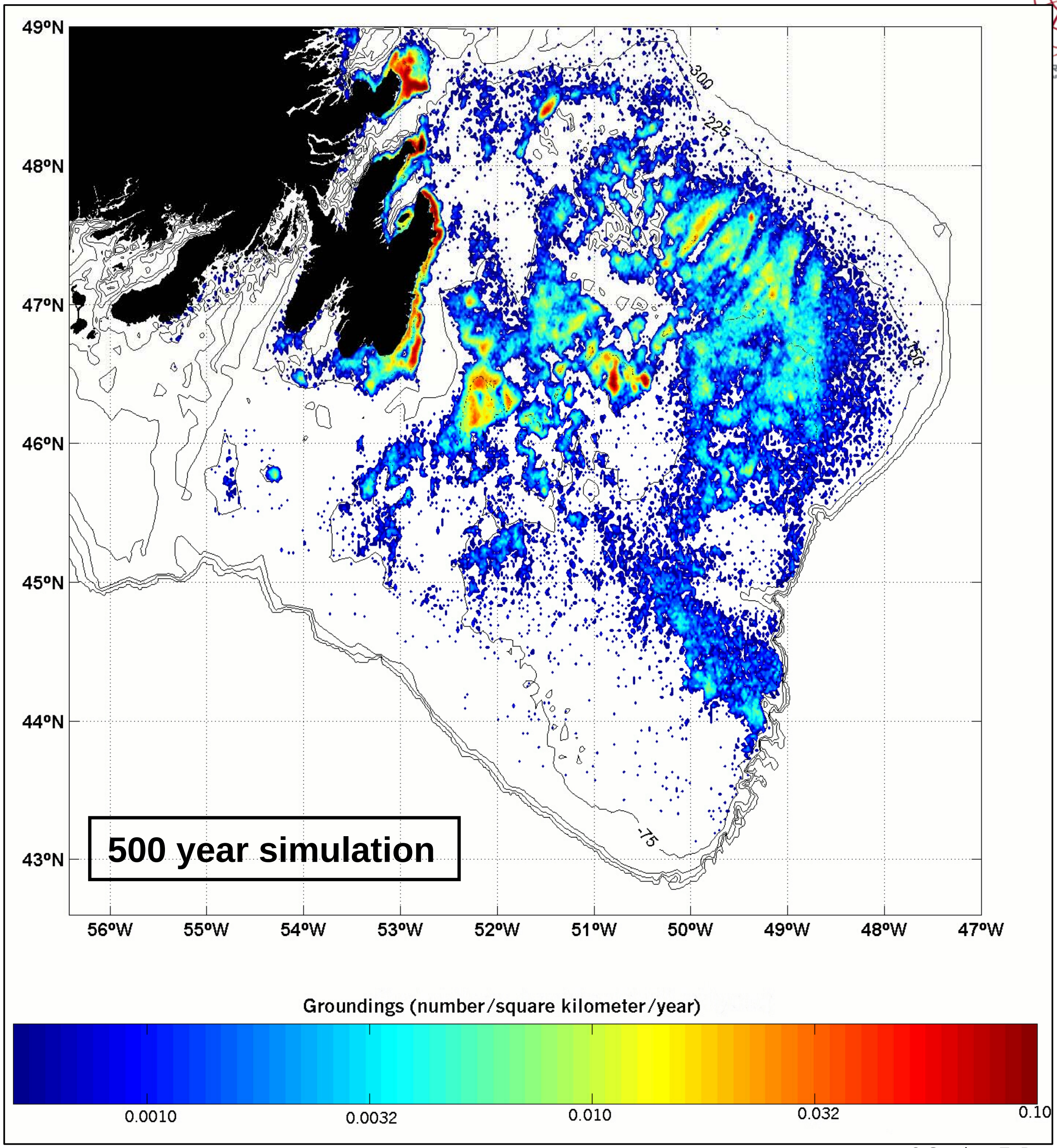


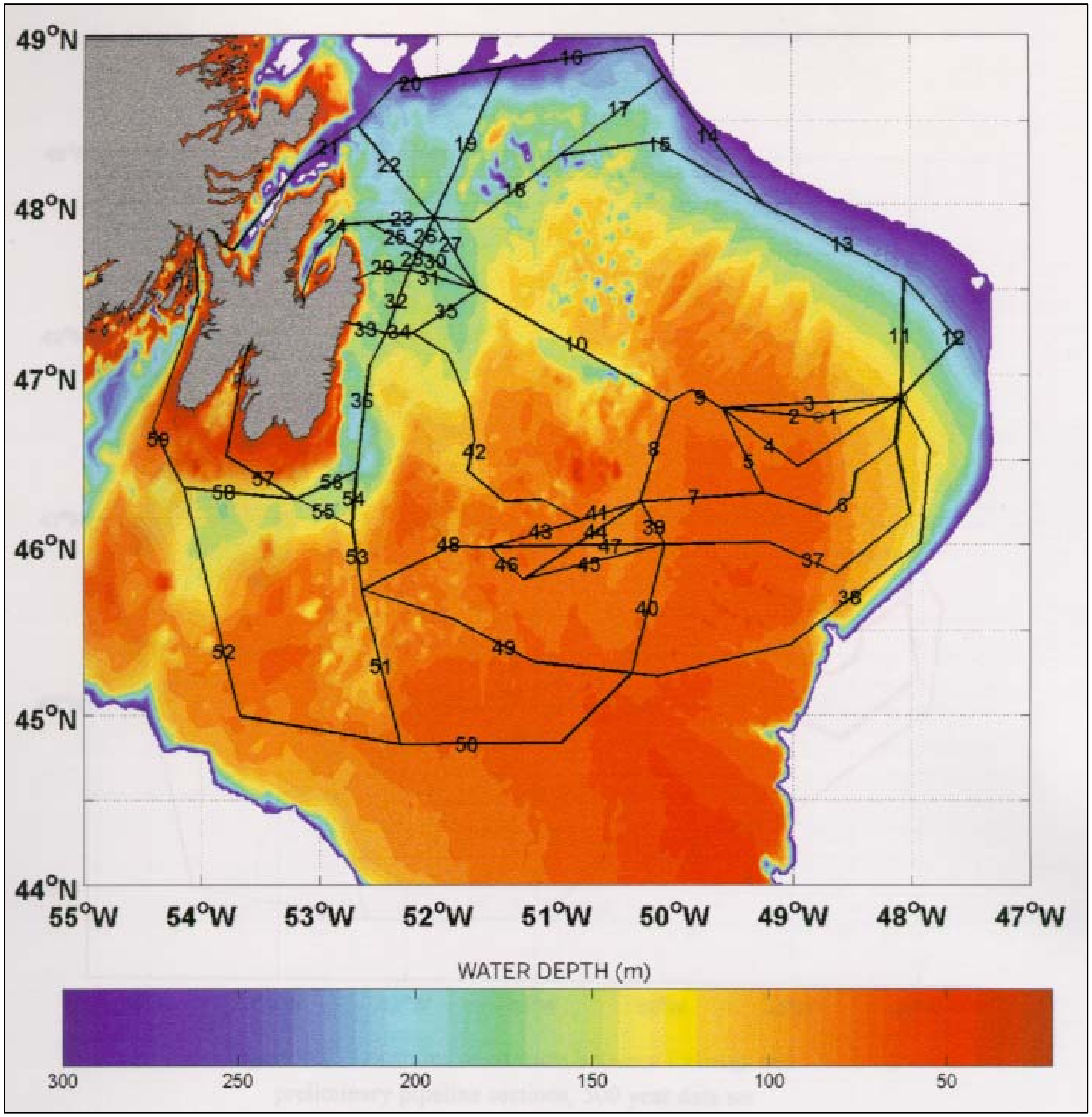
# Iceberg Grounding Risk Map

(Bruneau et al, 1999)
North Atlantic Pipeline Partners



# Route Assessment

(Bruneau et al, 1999) North Atlantic Pipeline Partners



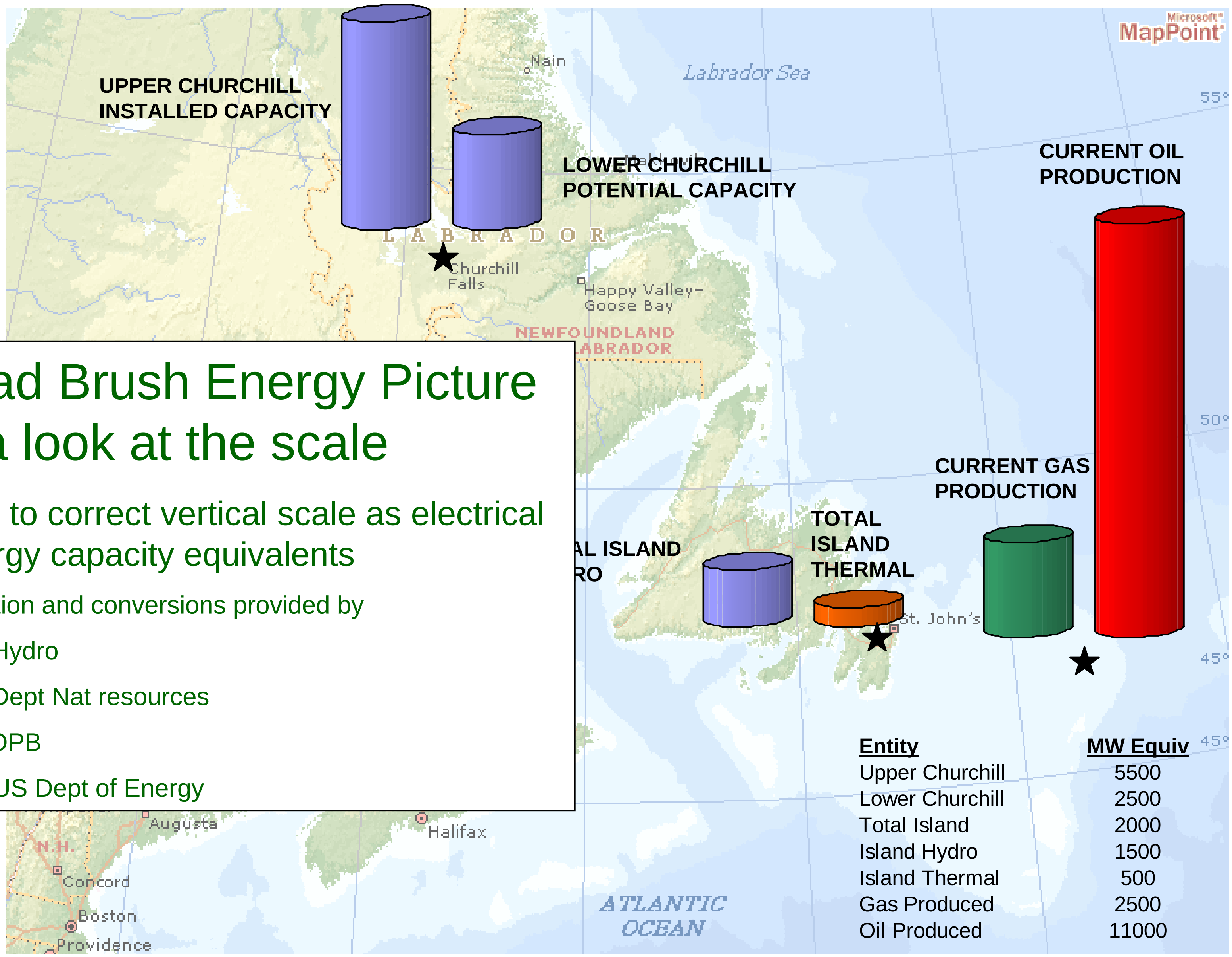
## Last note on pipeline costs

Iceberg Scour Risk to pipeline…

- NOIA study declared the problem “manageable”
- White Rose field pipeline analysis indicates low risk
- Proposed Avalon pipeline to be trenched
- In worst case normal repair protocols, times, costs applicable
- A lot safer than the alternative tanker traffic carrying crude.

# Natural Gas Resource Availability

# Availability of Gas Resources for On-Island Use




| Entity | MW Equiv |
|---|---|
| Upper Churchill | 5500 |
| Lower Churchill | 2500 |
| Total Island | 2000 |
| Island Hydro | 1500 |
| Island Thermal | 500 |
| Gas Produced | 2500 |
| Oil Produced | 11000 |

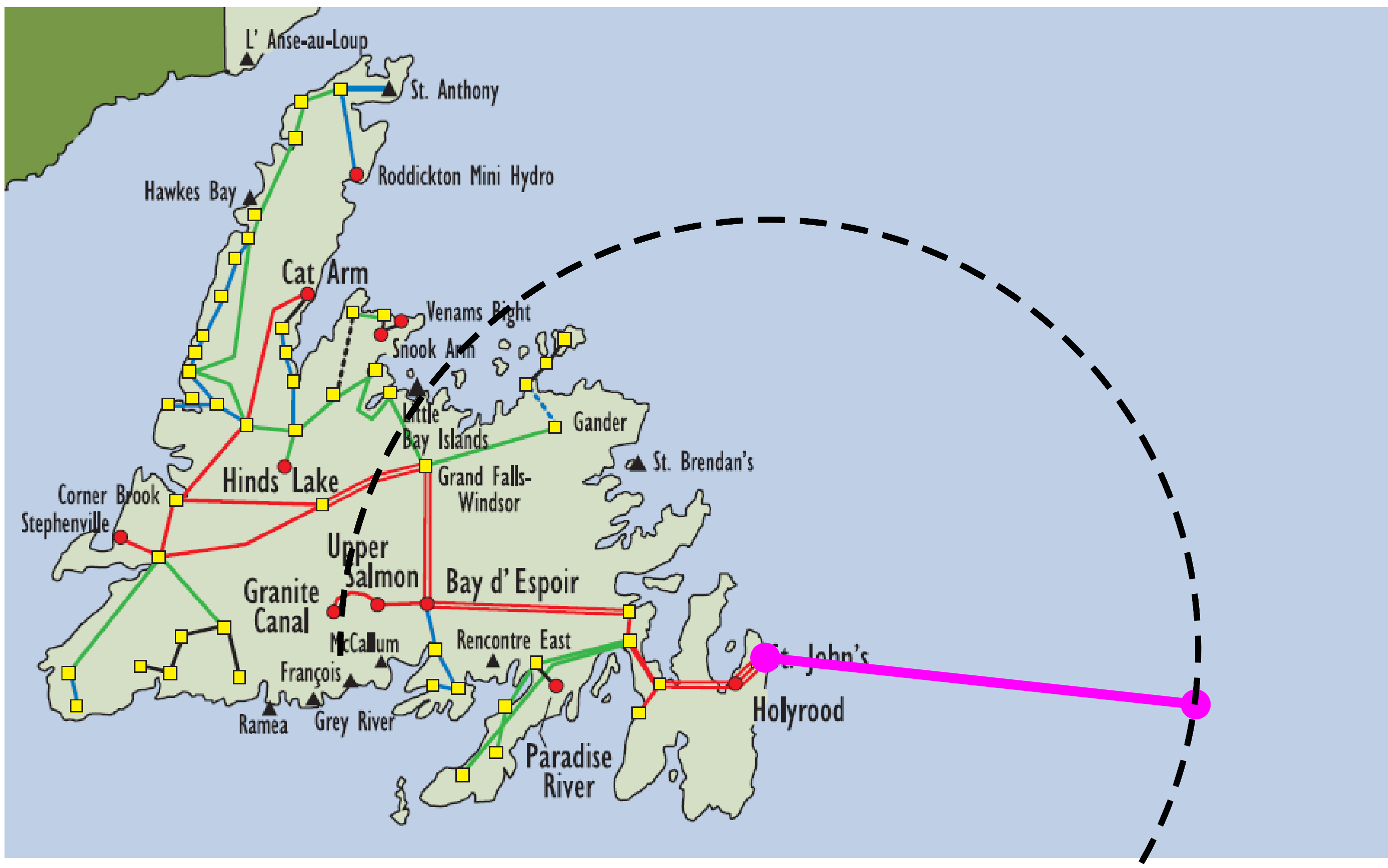
## Broad Brush Energy Picture – a look at the scale

drawn to correct vertical scale as electrical energy capacity equivalents

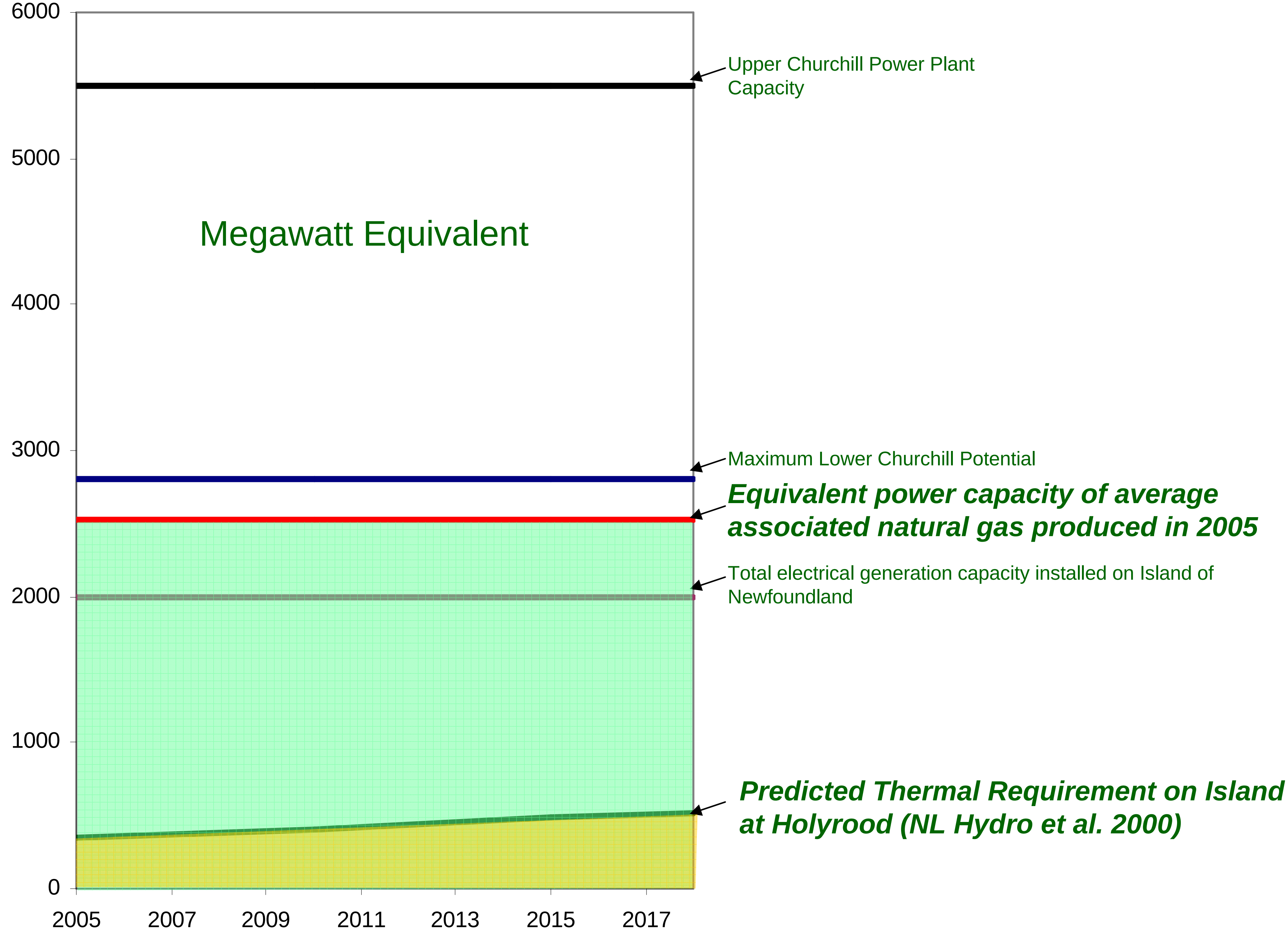
Information and conversions provided by

- N.L. Hydro
- Gov Dept Nat resources
- CNLOPB
- EIA, US Dept of Energy

# Proximity of Grand Banks Gas



# Availability of Gas Resources for On-Island Use



# <u>Availability of Gas Resources for On-Island use</u>

The average daily production of natural gas

- Hibernia in 2005 = 273 mmscf/g
- Terra Nova in 2005 = 106 mmscf/d
- White Rose in 2006 = 53 mmscf/d
- Therefore It can be safely assumed that:

***The average daily production of associated natural gas in 2006 and beyond will be in excess of 400 mmscf/d***

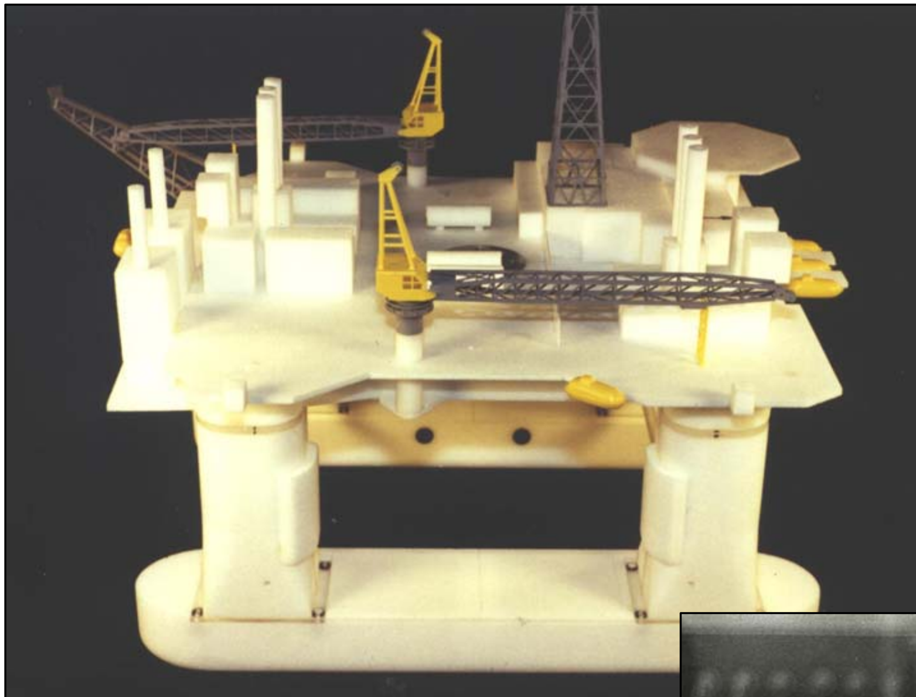
- Total gas consumed on these platforms for electrical power is around 15 or 20 mmscf/d
- The amount of gas required to enhance oil recovery is not common public knowledge – it appears that 100% at Terra Nova, 50% at Hibernia and 0% at White Rose are reasonable guesses, ie. 250mmscf/d leaving **150+ available**.
- The amount of gas that has been assumed (for the Avalon Pipeline economics) to supply our electrical energy needs in 2010 is **<u>80 mmscf/d</u>**
- The amount of gas that is produced now but reinjected and **lost permanently** may be over <u>100 mmscf/d</u> (CNOPB assumed 70% salvageable at W.R.)

# Producer's Costs and Oil Production Risks

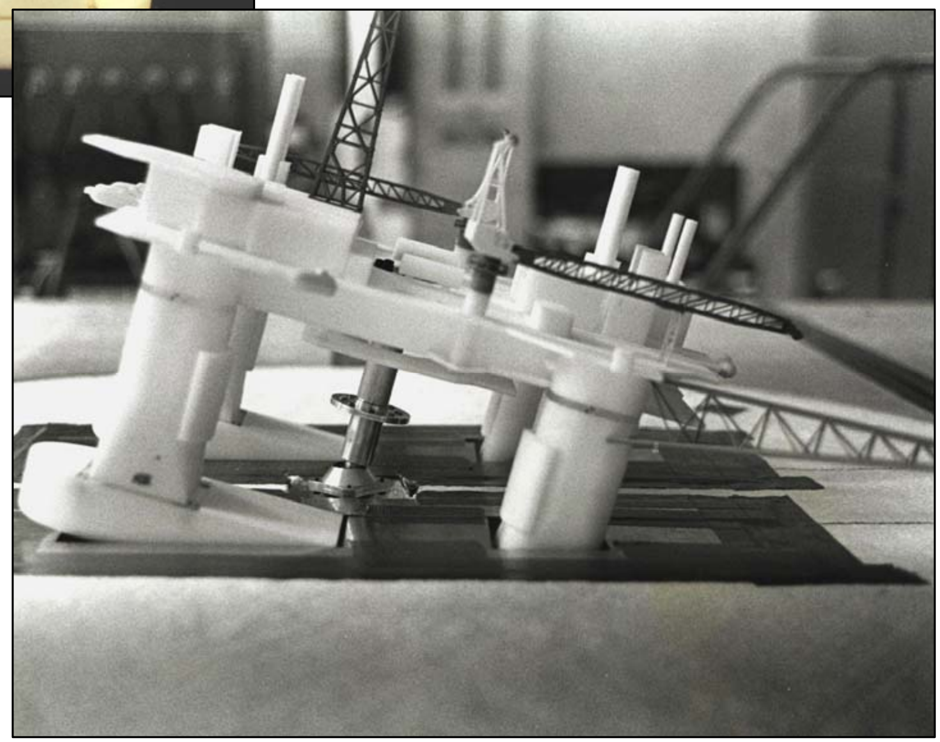
# Producers Costs and Oil Production Risks

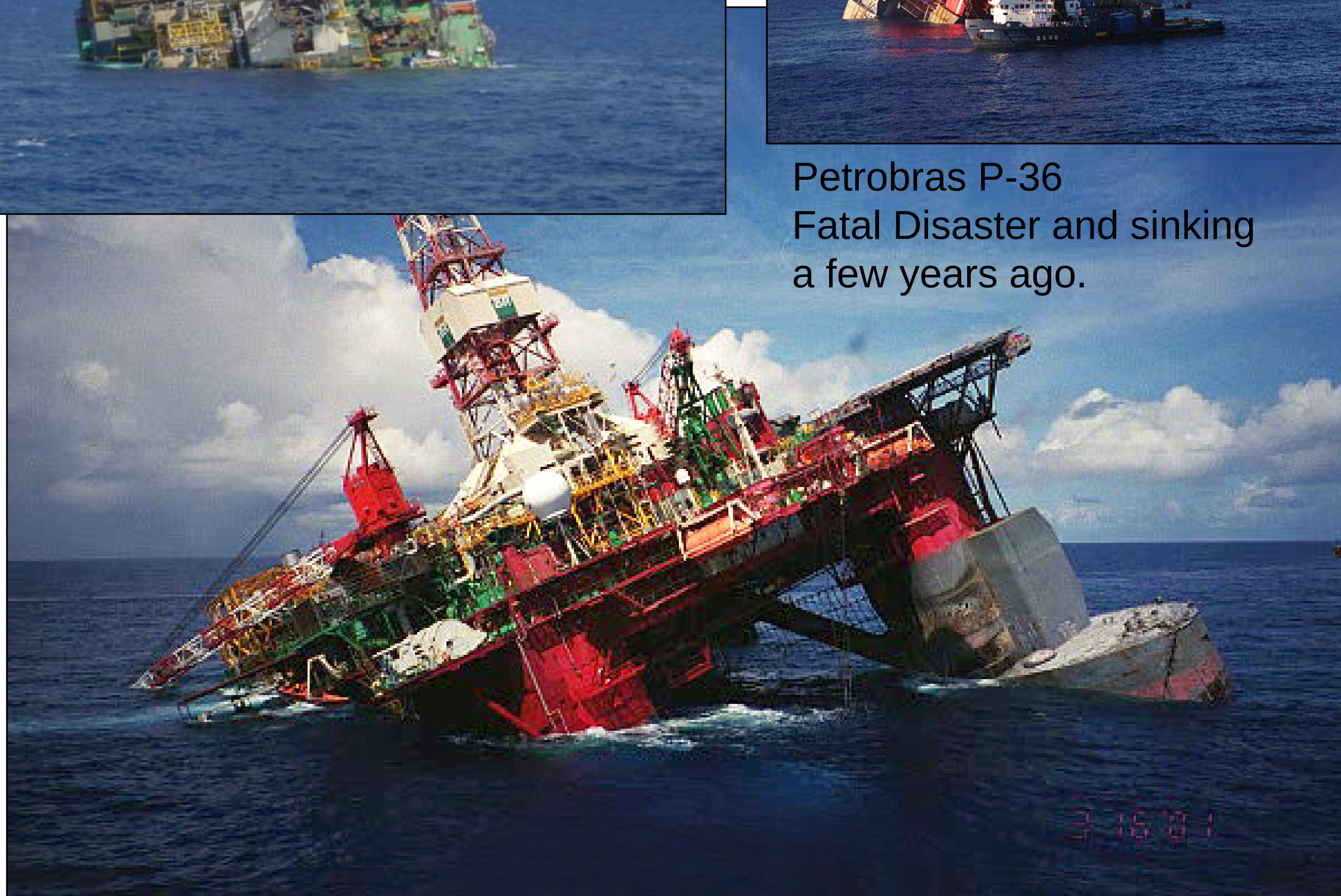
Not known clearly, but indicators exist

In approving the White Rose Development the CNLOPB reports that Maersk and Husky studied the refit question in 2001 and found that the most likely scenario was a refit cost of $75 million CAD with 12 weeks downtime – in order to facilitate a 150 mmscfgd export pipeline (approximately double Island requirements). This figure would, in all likelihood, move downwards as detailed engineering and operational optimization of scheduled maintenance were performed.



# Petrobras P-36
## Wind Tunnel Tests
University of Western Ontario 1990
S. Bruneau, S. Ramsay, A. Davenport





Petrobras P-36
Fatal Disaster and sinking
a few years ago.

## Owners Costs and Oil Production Risks

It is also probable that the modification costs and downtime associated with a domestic export line launched from Hibernia would be lower than this, and, that accommodation for same could be made on the yet-to-be-designed Hebron platform

Regardless, it appears that the likely maximum cost to the producer approaches \$200 million USD if downtime oil is considered “lost”.

# Economic Case Study for Avalon Pipeline

## Sample Gas Dev Economic Case Study:

CAPEX and OPEX conservatively estimated as follows:

***All in millions of USD***

- Platform preps = 200, Operating = 5
- Offshore Pipeline = 300, Operating = 10
- On-Shore Pipeline = 12.5, Operating = 2
- Power generation = 400, Operating = 15 + Fuel

# Where is this leading?

*The economic model assumptions:*

| | |
|---|---|
| Maximum platform modification and lost oil costs | $200 million USD |
| Daily average throughput in 2010 dropped to | 80 mmscf/d |
| Pipeline costs left (high) at | $300 million USD |
| Producers netback at platform left at | $2.0 USD/mscfd |
| Power plant costs left at 0.8 USD per Watt (turnkey) | $400 million USD |
| Infrastructure rate of return on equity pre tax | 10% |

All OPEX costs remain intact as presented for 22 year life of project

RESULT:

| | |
|---|---|
| ***Cost of electricity at the Holyrood gate*** | ***6 cents US / KWh*** |

***Though this model is simplistic and may be considered indicative only – it does indicate that the economics are realistic and compelling when compared to the costs of the alternatives, in particular, foreign crude.***

## Upside

- Proven operation of gas pipeline will quickly promote looping for enhanced deliveries for other end uses including on-Island LNG production. Looping provides additional supply security, and opens up other marginal developments on the Grand Banks.

- When gas throughput volumes increase, the IRR for the platform and the onshore infrastructure climbs providing flexibility for improved netback to producers and better electricity prices for consumers.

# Supply Reliability and Storage Requirements

# Energy Storage and Supply Security for natural gas-fired electricity on the Island of Newfoundland:

Options include:

- Standby oil-fired facilities or dual-fuel capabilities
- Standby distillate tank for combined cycle gas plant
- LNG peak shaving plant
- Third party storage facilities for backup fuel supply, such as
    - the proposed LNG trans-shipment,
    - NARL inventories
    - New Refinery

Preferred solution not known but lets look at an example:

# **Recall the Vancouver Island Pipeline** . . .

## In 2004 the following application was made:

Terasen Gas

LNG STORAGE PROJECT

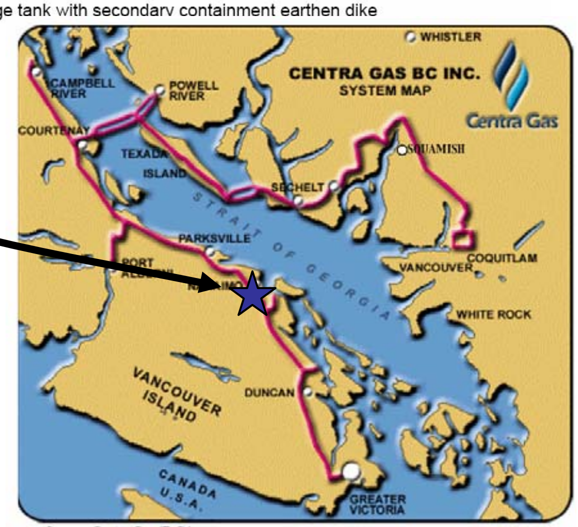
IN THE MATTER OF the Utilities Commission Act,
R.S.B.C. 1966, Chapter 473 (the "Act")

AND IN THE MATTER OF an Application by
Terasen Gas (Vancouver Island) Inc. for a
Certificate of Public Convenience and Necessity
Pursuant to Section 45 of the Act

Submitted to the
British Columbia Utilities Commission

August 2004

Conceptual Single containment storage tank with secondary containment earthen dike




Source: Centra Gas (B.C.)

## The LNG Storage Plan was devised to secure supply and meet increased Island peak demands without building a new supply pipeline

**Figure 14.1 LNG Facility Capital Costs (2004$millions)**

| | |
|---|---|
| EPC Costs | 73.8 |
| Owners Costs | |
| Land | 1.6 |
| Interconnecting Facilities | 9.3 |
| Project Services | 7.9 |
| Contingency | 1.8 |
| Total | 94.4 |

**Figure 14.2 LNG Facility Operating Costs (2004$000)**

| | |
|---|---|
| Fixed Operating | $ 930 |
| Variable Operating (excl gas) | $ 557 |
| Total | $1,487 |

**Figure 9.1 Primary Codes and Regulations**

| Code | Edition | Description |
|---|---|---|
| B.C. Pipeline Act and Pipeline Regulation | 2002 | Provincial Regulation of the Design, Construction and Operation of Pipeline Facilities |
| CSA Z 276 | 2001 | LNG Production, Storage, and Handling |
| CSA Z662 | 2003 | Oil and Gas Pipeline Systems |
| NBC | 1995 & Revisions | National Building Code of Canada |
| C.E.C. | 2002 | Canadian Electrical Code Part 1, 19th Edition |
| API 620 App. Q | 10th | Design and Construction of Large, Welded, Low Pressure Storage Tanks |
| CSA B51 | 1997 | Boiler, Pressure Vessel, and Pressure Piping Code |
| CAN/CSA A23.3-94 (R2000) | 2000 | Design of Concrete Structures |
| Terasen Standards | As Applicable | Standards for Equipment, Materials, Construction Procedures, Inspection, Testing, Security and Safety |

The powerline will be designed and constructed to BC Hydro Engineering and Construction Standards. The design and construction of the electrical substation will conform to the Canadian Electrical Code CSA 22.1

Terasen (owner) says:

- 30 months from start to finish
- Very robust, safe, economical
- Will liquify gas during low demand and regasify during high demand
- All codes and regs are in place
- Project has been approved by BC regulators

## LNG Elsewhere in N. America

Peak shaving LNG storage located at strategic points along gas pipelines are increasingly in use to provide additional grid storage. There are approx. 50 such facilities in the US.

The production, storage, truck transport and regasification of LNG is also well established in Canada

Currently three LNG plants operating in Canada - Tillbury Island (BC Gas), Hagar LNG plant (Union Gas), Montreal (Gaz Met.)

**Pine Needle Peak Shaving Facility, North Carolina**

**- 4 billion scf storage, 400 mmscfd regasification, 20 mmscfd liquifaction**

**- Total cost 107 Million USD**

**Tilbury LNG Plant (1971)**

**0.60 bcf storage, 200 mmscfd regas.**

**Hagar LNG Plant (1969)**

**0.61 bcf storage, 90 mmscfd regas.**

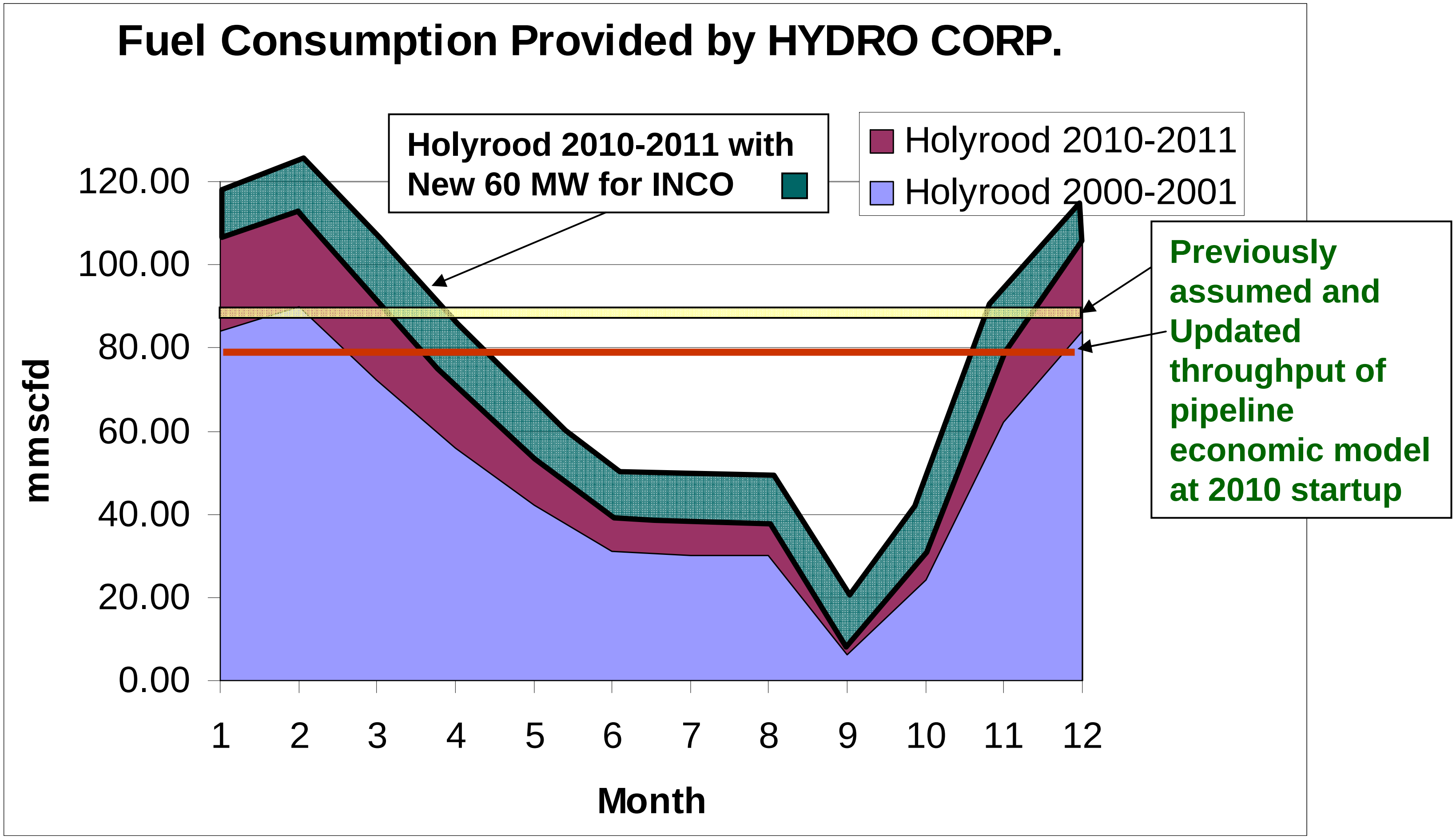
**Montreal LNG Plant (1970)**

**2.0 bcf storage, 280 mmscfd regas.**

# On-Island market size and seasonal variability

# On Island Market and Seasonal Variability

Absolute minimum gas demand would be Holyrood conversion ***only*** with low-level demand growth forecast as follows:



# On Island Market and Seasonal Variability

Other potential conversion customers in the future may include:


Legend

Potential Gas Customer

Facilities considered

1 - Holyrood Power Generating Station

2 - Memorial University Steam Plant

3 - St Claire's Hospital

4 - Labatt Brewery

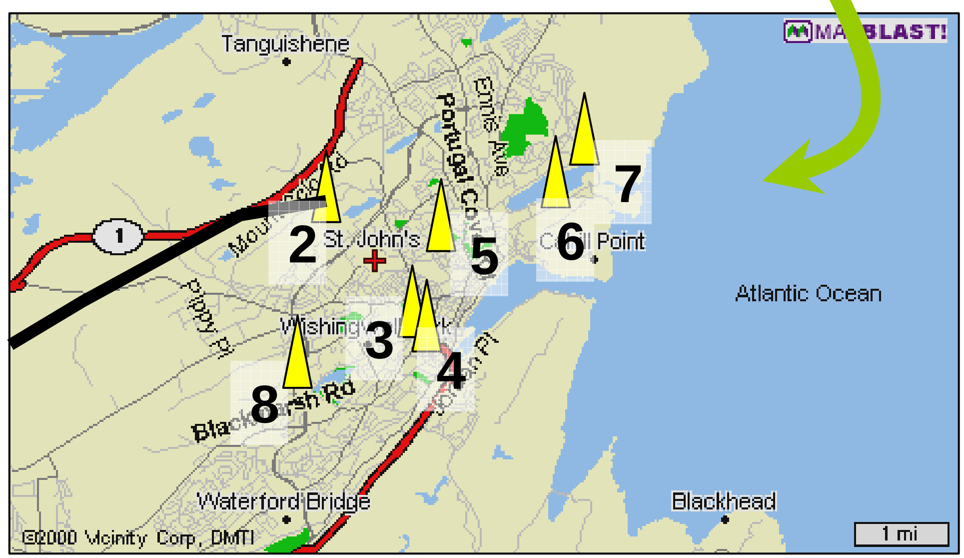
5 - Molson Brewery

6 - Miller Center

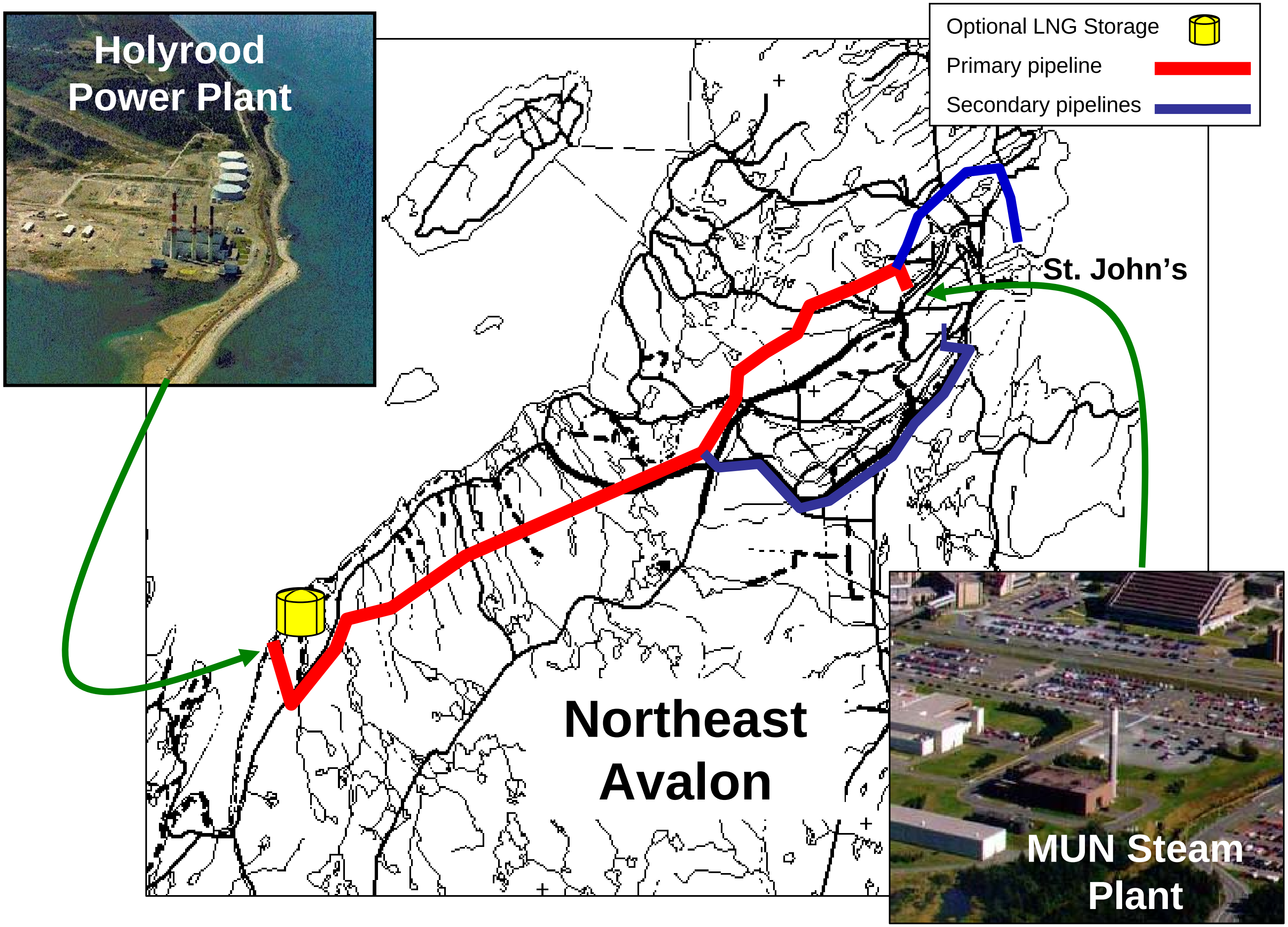
7 - Pleasantville Steam Plant

8 - Metrobus

9 - Come By Chance Oil Refinery



# On Island Market and Seasonal Variability




Opportunity here for combined cycle generation on campus with waste heat used for MUN

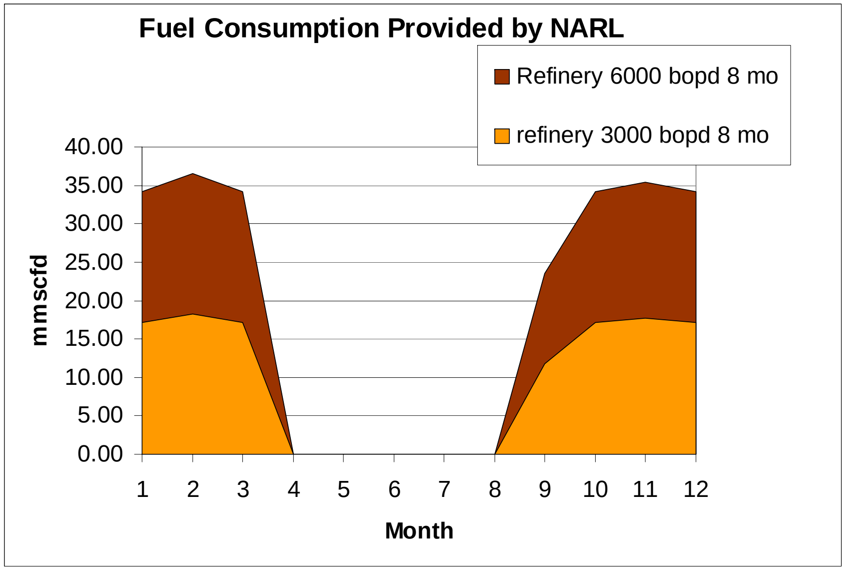
# On Island Market and Seasonal Variability

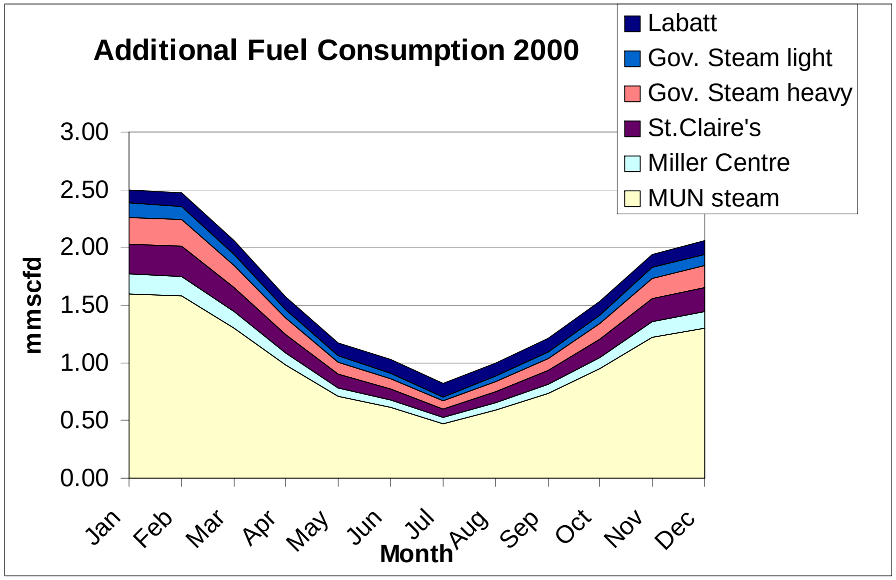
## On Island Demand Profile

Other minor conversions possible*

- Heavy Fuel Oil to Natural Gas
- May be supplied by trucking LNG or by pipeline

*** Does not include demand growth opportunities from INCO, refineries, pulp and paper other




*Figures are circa 2000-2001 Provided by indicated source*

# Summary of Gas Development Concept

- Resource base is easily in place today for Island requirements - major export pipeline gas quantities are not yet proven.
- Proposal uses gas from existing oil developments, and existing pipeline technology.
- Eliminates gas reinjection wastage and realizes higher present value of salvaged gas.
- Initially, gas remains stranded in Province for use/processing unlike a large grid-connecting pipeline with "postage stamp" tariff structure, i.e.., the price of stranded gas would be lower than the grid price.
- Provides for huge environmental benefit at negative cost

## CONCLUSION

***Associated gas transferred to the Island via pipeline is economical and is a wise choice for Newfoundland and Labrador energy strategy. It will result in lower electricity prices, improved environmental stewardship, will attract major industry including LNG export opportunities, and, is economical to begin IMMEDIATELY.***

# What can be done to advance this concept

Go and get unbiased, objective opinions from experts but we MUST

***Ask the right questions!***

- "Do we have the right to access this resource right now given the current rate of reinjection losses and our current domestic energy needs"?
- "If there is no royalty regime in place for gas then who owns the resource if it is an unused byproduct with zero book value to producers"?
- "What are the producers actual refit costs for a small export line"?
- "Can the unused natural gas resources available 300 km offshore be competitive with alternate foreign supply sources for Newfoundland"?

**Lets ask these questions and see what we get. . .**

# END OF PRESENTATION

**Many thanks for your attention on this and I look forward to your questions**

**Steve Bruneau**
**Memorial University of Newfounndland**
**Faculty of Engineering and Applied Science**

## So, why isn't it done? . . Because prior conditions were adverse:

1. Simplicity of oil-only developments was more attractive, less risky, for investment in this environmentally challenging region considered "frontier" for oil and "immature" for gas.

2. Gas resources were deemed insufficient to warrant producer-owned infrastructure linking Grand Banks to continental markets.

3. Early development options for gas pipelines were third-party initiatives that were viewed as meddling in the affairs of producers who were putting up the cash for the oil developments, and, threatened downstream control of resource flow and future profit taking.

4. Prior gas initiatives were based on the presumption that political and regulatory will could be captured. However, Governments were unwilling to risk scuttling oil developments or oil royalty talks on the technical and economic risks that producers stated would result from incorporating gas play. In addition, the regulator was too inexperienced or without the mandate to object.

## So Why Now?   What has changed?

1. NFLD Oil industry is maturing. Producers have conquered the risks of operating offshore Newfoundland through demonstrating fantastic profitability, safety and security through existing oil developments.

2. On the Island we can capture new power investments on a go-forward basis because very few new electric energy projects are on the books or committed to and policy review is ongoing

3. Acting now will reduce electrical price uncertainty from crude and improve availability to existing and new customers such as Abitibi, INCO, new refineries, etc

4. Acting now will give us access to our offshore gas resources prior to it becoming available to others at a higher price, ie, we must secure a recall quantity of the resource that satisfies domestic thermal needs before its value escalates to North American market prices

# So Why Now? What has changed?

***New conditions Continued . .***

- Commodity prices are very high now, relief may be in sight but vulnerability and uncertainty prevail. True cost of our oil dependency will be felt as our crude inventories are re-supplied and rate stabilization takes place through the PUB.

- The permanent loss of associated gas produced offshore occurs daily – and the losses are greater than our total requirements if we replaced oil at Holyrood with Grand Banks gas. Emissions would be curtailed by ½ million tons per annum immediately.